Annual Report of The Columbia River Treaty, Canada and United States Entities

1 October 1998 through
30 September 1999

November 1999

ANNUAL REPORT OF
THE COLUMBIA RIVER TREATY
CANADIAN AND UNITED STATES ENTITIES

FOR THE PERIOD

OCTOBER 1, 1998 - SEPTEMBER 30, 1999

Executive Summary

General

The Canadian Treaty projects, Mica, Duncan, and Arrow, were operated during the reporting period according to the 1998-99 and 1999-00 Detailed Operating Plans, the Flood Control Operating Plan, and several supplemental operating agreements described below. Throughout the year, Libby was operated according to the Flood Control Operating Plan, as amended. During a portion of the year, Libby was operated for power purposes according to the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER). During the remainder of the year, Libby was operated according to the Biological Opinions (BiOp) as recommended by both the U.S. Fish and Wildlife Service (USFWS) and the U.S. National Marine Fisheries Service (NMFS) and according to supplemental operating agreements described below.

During the reporting period, the Entities were not able to agree on an Assured Operating Plan (AOP) and Determination of Downstream Power Benefits (DDPB), as required by the Treaty, due to the dispute on fishery operations at Libby. However, in anticipation of potential settlements, the Entities did complete two sets of studies and draft 2003-04 AOP/DDPB documents, with and without the inclusion of the Libby minimum flows for sturgeon and salmon. In addition, the Entities have draft AOP/DDPB documents, with and without the effect of Libby minimum flows for sturgeon and salmon, for the 2000-01, 2001-02, and 2002-03 operating years.

On 1 April 1999 the second step-up of return of Canadian Entitlement power to British Columbia began flowing at the existing interconnections between Bonneville Power Administration (BPA) and British Columbia Hydro and Power Authority (B.C. Hydro). The amount delivered, not including transmission losses and scheduling adjustments, was 308.6 average MW at rates up to 830.6 MW. On 1 August 1999 the Canadian Entitlement return decreased slightly to 306.8 average MW at rates up to 801.7 MW.

Entity Agreements

Agreements approved by the Entities during the period of this report include:

- Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for 1 April 1998 through 15 September 2024, signed 29 March 1999 and effective 31 March 1999 with the diplomatic exchange of notes between the United States and Canada relating to Entitlement Disposal in the United States.

- Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for 1 August 1999, through 31 July 2000, signed 24 June 1999.

Operating Committee Agreements

Agreements approved by the Operating Committee include:

- Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for Nonpower Uses for 1 January through 31 July 1999, signed 1 December 1998.
- Agreement on Implementation of the Arrow Local Method for Treaty Storage for Operating Year 1998-99 Among the Columbia River Treaty Operating Committee, the Bonneville Power Administration, and the British Columbia Hydro and Power Authority, signed 22 December 1998.
- Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for Enhancement of Mountain Whitefish Emergence for 1 February through 31 July 1999, signed 22 February 1999.

- Columbia River Treaty Operating Committee Agreement on Operation of Treaty Storage for Enhancement of Mountain Whitefish Spawning for the Period 1 September 1999 through 30 April 2000, signed 24 August 1999.

System Operation

The coordinated system filled to 99.39 percent of capacity by 31 July 1998, in the Actual Energy Regulation (AER) study that implements the Pacific Northwest Coordination Agreement (PNCA) operating plan. The AER hydro-system monthly power model demonstrates an operation for U.S. projects that meets firm load and all non-power requirements. A subset of the AER is the Treaty Storage Regulation (TSR) operation for Canadian Treaty storage. The TSR is developed based on the Assured Operating Plan (AOP) and Detailed Operating Plan (DOP) for Canadian storage. Once the TSR is completed for Canadian Storage it is input to the AER as a fixed parameter. Since the AER was 99.39 percent full on 31 July 1998, first year firm load carrying capability (FLCC) was adopted for the

1998-99 operating year. Due to above average streamflows throughout the year, the system generally operated to Operating Rule Curve or Flood Control Curve for the entire period.

The 1 January 1999 water supply forecast for the Columbia River at the Dalles (January-July) was 116.0 million acre-feet (Maf), or 110 percent of the 1961-90 average. Above average precipitation persisted throughout the spring. As a result, the water supply generally increased, and remained above average through the January through July period. The runoff was characterized by being very late in 1999. May and June temperatures were well below normal causing the bulk of the runoff to be shaped into July and August. The unregulated runoff at The Dalles for January through July was 124.1 Maf, which is 117 percent of normal. The observed peak daily average flow observed at The Dalles was 379,000 cubic feet per second (cfs) on 4 June 1999.

The lower Columbia River flow was regulated for juvenile fish between 3 April and 31 August based on recommendations of the "Technical Management Team" (TMT) consisting of representatives from five U.S. Federal agencies. State fishery agencies and Indian tribes also provided input at the TMT meetings. This information was usually provided through the Fish Passage Center (FPC). The TMT's Executive and Technical groups make recommendations to the two operating agencies (Corps of Engineers and Bureau of Reclamation) on flow and operations to optimize passage conditions for juvenile and adult anadromous salmons in the lower Snake and Columbia Rivers in accordance with the National Marine Fisheries Service's 1995 Biological Opinion and the 1998 Supplemental Biological Opinion (BiOp). The 1995 Biological Opinion also addresses operations recommended by the USFWS for sturgeon. Each year, the TMT will also prepare a Water Management Plan to meet various fishery, flow, reservoir operation, and other objectives.

Coordinated System storage energy in the AER reached a level of 99.87 percent of full on 31 July 1999. This value was used to determine the Firm Load Carrying Capability (FLCC), with first-year FLCC being adopted for the 1999-2000 operating year.

From 1 August 1998 through 31 March 1999, generation at downstream projects in the United States, delivered to the Columbia Storage Power Exchange (CSPE) participants under the Canadian Entitlement Exchange Agreement was approximately 215 average megawatts.
From 1 April through 31 July 1999, the delivery was 103 average megawatts. All CSPE power was used to meet Pacific Northwest loads.

From 1 August 1998 through 31 March 1999 the Canadian entity delivered 3.7 average megawatts of energy and 0.4 megawatts of dependable capacity to the U.S. Entity under the Canadian Entitlement Purchase Agreement, and between 1 April 1999 and 31 July 1999, the Canadian Entity delivered 0.4 average megawatts of energy and no dependable capacity to the U.S. entity under the CSPE/CEPA.

Treaty Project Operation

The Canadian Treaty projects, Duncan, Mica and Arrow, were operated throughout the year in accordance with the 1998-99 Detailed Operating Plan as amended by the U.S. Army Corps of Engineers (USACE) "Review of Flood Control, Columbia River Basin, Columbia River & Tributaries Study, CRT-63", dated June 1981, the Flood Control Operating Plan, and the Operating Committee Agreements. Throughout the year, Libby reservoir was operated in accordance with the same amended flood control operating plan. During the fall of 1998, the U.S. Entity operated Libby for power requirements according to the PNCA AER. From 31 December 1998, and during the remainder of the operating year, the U.S. Entity operated Libby for storage and releases to meet both the USFWS and the U.S. National Marine Fishery Service Biological Opinions. The Canadian Entity has given notice that it considers the U.S. Entity's decision to independently operate Libby for the U.S. BiOp fishery operation, rather than the rule curves developed and agreed to in the Assured Operating Plans, to be inconsistent with the Columbia River Treaty.

The Mica Treaty storage account was 6.5 million acre-feet (Maf) on 31 July 1998 and with continued storing reached 7.0 Maf or 100 percent full content on 13 August 1998. The actual reservoir elevation reached a maximum elevation of 2466.6 (8.4 feet below full) on 10 September. By 31 December, Treaty storage was drafted to 4.6 Maf, and the observed reservoir level had dropped to elevation 2417.8 feet. Treaty storage was completely drafted by 2 May 1999. The reservoir had reached its lowest level for the 1998-1999 water year, elevation 2373.5 feet, on 20 April 1998. From then on, Mica Treaty storage refilled reaching 95 percent full at 6.7 Maf, on 31 July 1999. The maximum level for 1999 was elevation 2474.6 feet (0.4 feet below normal full pool) and was reached on 31 August 1999.

The Arrow Treaty storage account started the 1998-99 operating year 100 percent full at 7.1 Maf on 31 July 1998. The reservoir was drafted to elevation 1430.8 feet by 31 December 1998 with a Treaty storage of 5.8 Maf, or 81 percent of full. Arrow Reservoir reached its lowest level of the year at elevation 1383.9 feet on 25 March 1999. Arrow Treaty storage reached its annual minimum on 24 March 1999 at

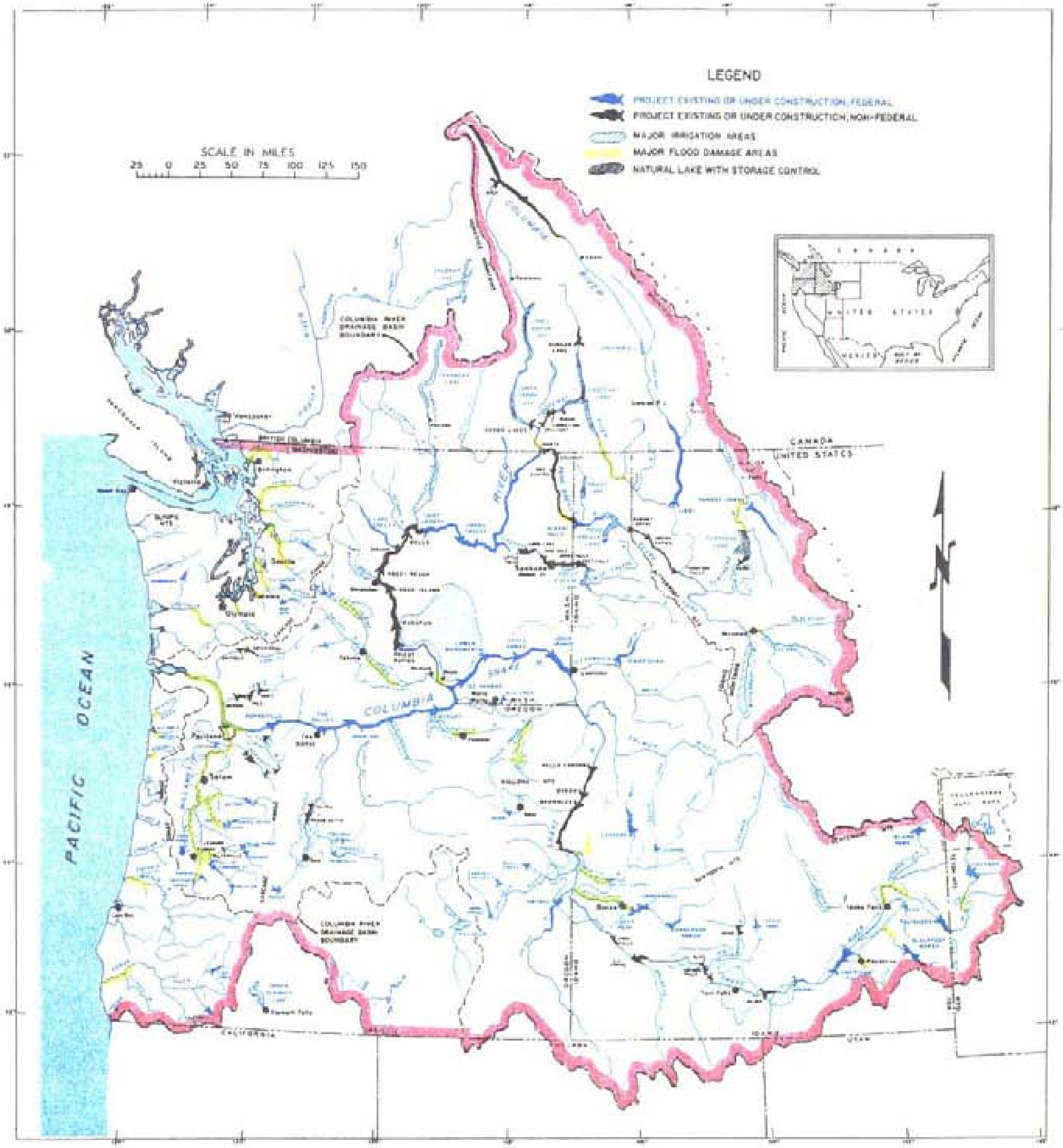
0.35 Maf, or 5 percent of full. In late December 1998, Arrow outflows were selectively reduced below Treaty requests to keep river levels at acceptable and maintainable levels during the whitefish spawning and emergence period from 24 December to 21 January 1998. With low discharges in April and May, the Arrow Reservoir filled to elevation 1395.5 feet by 30 April 1999. April through early May, and in June, outflows were held at about 20,000 cubic feet per second (cfs) through this period. Maintenance of low flows over this period was undertaken to ensure rainbow trout would not spawn at higher river levels immediately downstream of Arrow. The reservoir reached its highest elevation on 29 July 1999 at elevation 1443.8 feet with the Treaty storage content reaching full 7.1 Maf on 1 August 1999. To minimize spill at the Canadian Kootenay River plants and maintain Koocanusa reservoir water levels in Canada for resident fish and recreation, a Libby-Arrow water transfer of 107 thousand second feet per day (ksfd) was negotiated which increased the Arrow discharges in July and August and concurrently reduced Libby releases by the same amount. This water was returned to Arrow Reservoir during the 17 September to January period. In July, outflows were increased and the Arrow outflow peaked at 94,000 cfs on 11 August 1999, approximately one week later than the previous year. The Arrow Reservoir drafted to elevation 1437.8 feet by the end of August.

Duncan reservoir elevation on 31 July was at 1891.7 feet with Treaty storage filled to 99.7 percent of full capacity (1.4 Maf). The reservoir reached an elevation of 1892.1 feet on 13 August 1998. The project passed inflow for the remainder of August to maintain the reservoir near full pool. During September through December, Duncan was used to support the Kootenay Lake levels and increase Kootenay River flows. By 31 December the reservoir had drafted to 1830.7 feet (30 percent of full). The reservoir continued to draft and reached its lowest level for the year at elevation 1794.4 on 20 March 1999. Minimum release during May to 20 July caused the reservoir to refill to an elevation 1892.0 feet by 20 August 1999. Duncan passed inflow for the remainder of August and until the first week in September 1999 to maintain the reservoir near full pool. Duncan discharge was increased at the end of first week in September to start drafting the reservoir and keep the Kootenay reservoir close to the IJC limit. The Duncan reservoir remained at or below the flood control curve throughout the operating year.

During the 1998-99 operating year, Lake Koocanusa began August 1998 at Elevation 2457.31 feet (1.69 feet below full pool). The Libby/Arrow storage exchange agreement between the U.S. and Canada was implemented on 1 August and resulted in an exchange of 107 ksfd . By the end of August, Lake Koocanusa was at Elevation 2443.9 feet. The project was drafted to 2405.6 feet by the end of December, 5.4 feet below the Upper Rule Curve. Project releases were held at 6,000 cfs for a one-week period in January to provide Idaho Department of Fish and Game a chance to monitor burbot movement below Libby. Project releases in the spring considered flood control, sturgeon flows, refill for recreation and salmon flows. One sturgeon pulse was provided in June and incubation flows of 30,000 cfs at Bonners Ferry were held for 18 days following the pulse. This operation was coordinated with the U.S. Fish and Wildlife Service. Libby reached its maximum level of 2458.97 (0.03 feet from full) on 9 August 1999. No Libby/Arrow storage exchange agreement was signed in 1999. Because of an abundance of water in the Columbia Basin, McNary Biological Opinion flow objectives were met while drafting Libby to only 2455.63 feet at the end of August, 3.3 feet from full and 16.63 feet above the 1995 Biological Opinion interim draft limit of 2439 feet. By the end of September, Lake Koocanusa drafted to 2449.12 feet.

Columbia Basin Map

COLUMBIA RIVER AND COASTAL BASINS



1999 Report of the Columbia River Treaty Entities
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1999 Report of The Columbia River Treaty Entities
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I Introduction

This annual Columbia River Treaty Entity Report is for the 1999 Water Year, 1 October 1998 through 30 September 1999. It includes information on the operation of Mica, Arrow, Duncan, and Libby reservoirs during that period with additional information covering the reservoir system operating year, 1 August 1998, through 31 July1999. The power and flood control effects downstream in Canada and the United States are described. This report is the thirty-third of a series of annual reports covering the period since the ratification of the Columbia River Treaty in September 1964.

Duncan, Arrow, and Mica reservoirs in Canada and Libby reservoir in the United States of America were constructed under the provisions of the Columbia River Treaty of January 1961. Treaty storage in Canada is operated for the purposes of flood control and increasing hydroelectric power generation in Canada and the United States of America. In 1964, the Canadian and the United States governments each designated an Entity to formulate and carry out the operating arrangements necessary to implement the Treaty. The Canadian Entity is the British Columbia Hydro and Power Authority (B.C. Hydro). The United States Entity is the Administrator of the Bonneville Power Administration (BPA) and the Division Engineer of the Northwestern Division, U.S. Army Corps of Engineers (USACE).

The following is a summary of key features of the Treaty and related documents:

1. Canada is to provide 15.5 million acre-feet (Maf) of usable storage. This has been accomplished with 7.0 Maf in Mica, 7.1 Maf in Arrow and 1.4 Maf in Duncan.

2. For the purpose of computing downstream power benefits the U.S. base system hydroelectric facilities will be operated in a manner that makes the most effective use of the improved streamflow resulting from operation of the Canadian storage.

3. The U.S. and Canada are to share equally the downstream power benefits generated in the U.S. resulting from operation of the Canadian storage.

4. The U.S. paid Canada a lump sum of the $64.4 million (U.S.) for one half of the present worth of expected future flood control benefits in the U.S. resulting from operation of the Canadian storage.

5. The U.S. has the option of requesting the evacuation of additional flood control space above that specified in the Treaty, for a payment of $1.875 million (U.S.) for each of the first four requests for this "on-call" storage.

6. The U.S. had the option (which it exercised) to construct Libby Dam with a reservoir that extends 42 miles into Canada and for which Canada agreed to make the land available.

7. Both Canada and the United States have the right to make diversions of water for consumptive uses. In addition, since September 1984 Canada has had the option of making for power purposes specific diversions of the Kootenay River into the headwaters of the Columbia River.

8. Differences arising under the Treaty which cannot be resolved by the two countries may be referred to either the International Joint Commission (IJC) or to arbitration by an appropriate tribunal.

9. The Treaty shall remain in force for at least 60 years from its date of ratification, 16 September 1964.

10. In the Canadian Entitlement Purchase Agreement of 13 August 1964, Canada sold its entitlement to downstream power benefits to the United States for 30-years beginning at Duncan on 1 April 1968, at Arrow on 1 April 1969, and at Mica on 1 April 1973.

11. Canada and the U.S. are each to appoint Entities to implement Treaty provisions and are to jointly appoint a Permanent Engineering Board (PEB) to review and report on operations under the Treaty.

II Treaty Organization

Entities

There was one meeting of the Columbia River Treaty Entities (including the Canadian and U.S. Entities and Entity Coordinators) during the year on the morning of 2 February 1999 in Vancouver, B.C. The members of the two Entities at the end of the period of this report were:

UNITED STATES ENTITY
Ms. Judith A. Johansen, Chair
Administrator & Chief Executive Officer
Bonneville Power Administration
Department of Energy
Portland, Oregon

Brigadier General Carl A. Strock, Member
Division Engineer
Northwestern Division
Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY
Mr. Brian R. D. Smith, Chair
British Columbia
Hydro and Power Authority
Vancouver, British Columbia

BG Carl A. Strock succeeded BG Robert H. Griffin effective 15 July 1999.

The Entities have appointed Coordinators, Secretaries and two joint standing committees to assist in Treaty implementation activities that are described in subsequent paragraphs. The primary duties and responsibilities of the Entities as specified in the Treaty and related documents are to:

1. Plan and exchange information relating to facilities used to obtain the benefits contemplated by the Treaty.

2. Calculate and arrange for delivery of hydroelectric power to which Canada is entitled and the amounts payable to the U.S. for standby transmission services

3. Operate a Hydrometeorological system.

4. Assist and cooperate with the Permanent Engineering Board in the discharge of its functions.

5. Prepare hydroelectric and flood control operating plans for the use of Canadian storage.

6. Prepare and implement detailed operating plans that may produce results more advantageous to both countries than those that would arise from operation under assured operating plans.

Additionally, the Treaty provides that the two governments by an exchange of diplomatic notes may empower or charge the Entities with any other matter coming within the scope of the Treaty.

Entity Coordinators & Secretaries

The Entities have appointed Coordinators from members of their respective staffs to help manage and coordinate Treaty related work, and Secretaries to serve as information focal points on all Treaty matters within their organizations.

The members are:

UNITED STATES ENTITY COORDINATORS

Gregory K. Delwiche, Coordinator
Vice President, Generation Supply
Bonneville Power Administration
Portland, Oregon

Michael B. White, Acting Coordinator
Director, Programs and Project Management
Northwestern Division
Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY COORDINATOR

T. J. (Tim) Newton, Coordinator
Vice President, Strategic Planning
POWEREX
Vancouver, British Columbia

UNITED STATES ENTITY SECRETARY

Dr. Anthony G. White
Regional Coordination
Power and Operations Planning
Bonneville Power Administration
Portland, Oregon

CANADIAN ENTITY SECRETARY

Douglas A. Robinson
Resource Management
Power Supply
BC Hydro and Power Authority
Burnaby, British Columbia

Mr. Michael B. White was appointed to succeed Mr. James Crews, effective 1 August 1999.

Columbia River Treaty Operating Committee

The Operating Committee was established in September 1968 by the Entities, and is responsible for preparing and implementing operating plans as required by the Columbia River Treaty, making studies and otherwise assisting the Entities as needed. The Operating Committee consists of eight members as follows:

UNITED STATES SECTION	CANADIAN SECTION
Richard M. Pendergrass, BPA, Co-Chair	Ralph D. Legge, B.C. Hydro, Chair
William E. Branch, USACE, Co-Chair	Kenneth R. Spafford, B.C. Hydro
Cynthia A. Henriksen, USACE	Kelvin Ketchum, B.C. Hydro
John M. Hyde, BPA	Dr. Thomas K. Siu, B.C. Hydro

Mr. Pendergrass was appointed to succeed Mr. Gregory K. Delwiche on 9 November 1998.

The Committee met six times during the reporting period to exchange information, review and discuss operating plans and issues, and approve work plans. The meetings were held every other month from September 1998 alternating between Canada and the U.S. The Committee also met numerous times to discuss and negotiate a proposal to resolve the Libby dispute. The Operating Committee coordinated the operation of the Treaty storage in accordance with the current hydroelectric and flood control operating plans. This aspect of the Committee's work is described in following sections of this report, which have been prepared by the Committee with the assistance of others. During the period covered by this report, the Operating Committee completed the 1 August 1998 through 31 July 1999 Detailed Operating Plan (DOP).

Columbia River Treaty Hydrometeorological Committee

The Hydrometeorological Committee was established in September 1968 by the Entities and is responsible for planning and monitoring the operation of data facilities in accord with the Treaty and otherwise assisting the Entities as needed. The Committee consists of four members as follows:

UNITED STATES SECTION	CANADIAN SECTION
Nancy L. Stephan, BPA Co-Chair	Eric Weiss, B.C. Hydro, Chair
Peter F. Brooks, USACE, Co-Chair	Don Druce, B.C. Hydro, Member

The only committee meeting (No. 45) for the year was hosted by BC Hydro in Vancouver, BC on 18 November 1998. There were eight attendees, including Peter Richards from BC Hydro and Robin McNeil from the BC Ministry of Environment, Lands and Parks.

A major part of the meeting dealt with the continuing issue of Treaty stations vs. Support stations as defined in the Terms of Reference for the Hydromet Committee. The discussion centered around whether the current definitions of Treaty and Support hydromet stations were still representative of the current needs for forecasting and monitoring Treaty operations on the Columbia River. Since the original list of stations was developed, there have been numerous changes to the way Treaty operations are determined and monitored, including: changes to water supply forecasting techniques, station closures due to budget cuts, use of Treaty Storage Regulation studies, etc. During the course of discussions, the Committee saw the potential for the station list to grow with all these changes. In light of funding issues, this was foreseen as being a problem. In order to answer the funding question, as well as the issue of the list itself, the Committee decided that each section would compile a list of stations required for Treaty water supply forecasting and operations. Once this list was compiled the Committee felt they would have a better idea of the magnitude of the number of stations they were dealing with and could proceed with making decisions on how to define Treaty stations and/or Support stations.

In addition to the Treaty station discussion, Robin McNeil also made a presentation on the Ministry's budget cutbacks and how this may impact the snow survey network. One of the measures being implemented was the replacement of snow surveys with snow pillows. Robin was attending the Columbia River Water Management Group (CRWMG) meeting to provide information on his Ministry's efforts and to learn more about the snow survey requirements of the Columbia River Treaty.

Other meeting topics included a review of the past year's reservoir operations, water supply forecasts, and weather. Peter Richards reported on the successful conversion of the data transfer for the CROHMS/CAFÉ to FTP and that the old systems have been discontinued. Various discussions also occurred regarding improving and streamlining the transfer of data between all agencies and organizations.

Permanent Engineering Board

Provisions for the establishment of the Permanent Engineering Board (PEB) and its duties and responsibilities are included in the Treaty and related documents. The members of the PEB are presently:

UNITED STATES SECTION	CANADIAN SECTION
Stephen L Stockton, Chair San Francisco, California Ronald H. Wilkerson, Member Missoula, Montana	Daniel R. Whelan, Chair Ottawa, Ontario Charles S. Kang, Member Victoria, British Columbia
Earl E. Eiker, Alternate nominee Washington, D.C. George E. Bell, Alternate Portland, Oregon	Prad Kharé, Alternate Victoria, British Columbia David E. Burpee, Alternate Ottawa, Ontario
Richard J. DiBuono, Secretary Washington, D.C.	David E. Burpee, Secretary Ottawa, Ontario

Under the Treaty, the PEB is to assemble records of flows of the Columbia River and the Kootenay River at the international boundary. It is also to report to both governments if there is deviation from the hydroelectric or flood control operating plans, and if appropriate, include recommendations for remedial action. Additionally, the PEB is to:

- assist in reconciling differences that may arise between the Entities;
- make periodic inspections and obtain reports as needed from the Entities to assure that Treaty objectives are being met;
- prepare an annual report to both governments and special reports when appropriate;
- consult with the Entities in the establishment and operation of a Hydrometeorological system; and
- investigate and report on any other Treaty related matter at the request of either government.

The Entities continued their cooperation with the PEB during the past year by providing copies of Entity agreements, operating plans, downstream power benefit computations, Operating Committee agreements, corrections to Hydrometeorological documents, and the annual Entity report to the Board for their review. The annual joint meeting of the PEB and the Entities was held on the morning of 2 February 1999, in Vancouver, British Columbia, where the Entities briefed the PEB on the preparation and implementation of operating plans and the delivery of the Canadian Entitlement. The Entities also met with the PEB for a special meeting on 24 August 1999, to brief the PEB on progress to resolve the dispute on the operation of Libby for nonpower requirements and the completion of past due AOP's.

PEB Engineering Committee

The PEB has established a PEB Engineering Committee (PEBCOM) to assist in carrying out its duties. The members of PEBCOM at the end of the period of this report were:

UNITED STATES SECTION	CANADIAN SECTION
Richard J. DiBuono, Chair Washington, D.C.	Roger S. McLaughlin, Chair Victoria, British Columbia
Michael S. Cowan, Member Golden, CO	Larry N. Adamache, Member Vancouver, British Columbia
James D. Barton, Member Portland, OR	Myriam Boudreault, Member Ottawa, Ontario
D. James Fodrea, Member Washington, D.C.	Dr. G. Bala Balachandran, Member Victoria, British Columbia

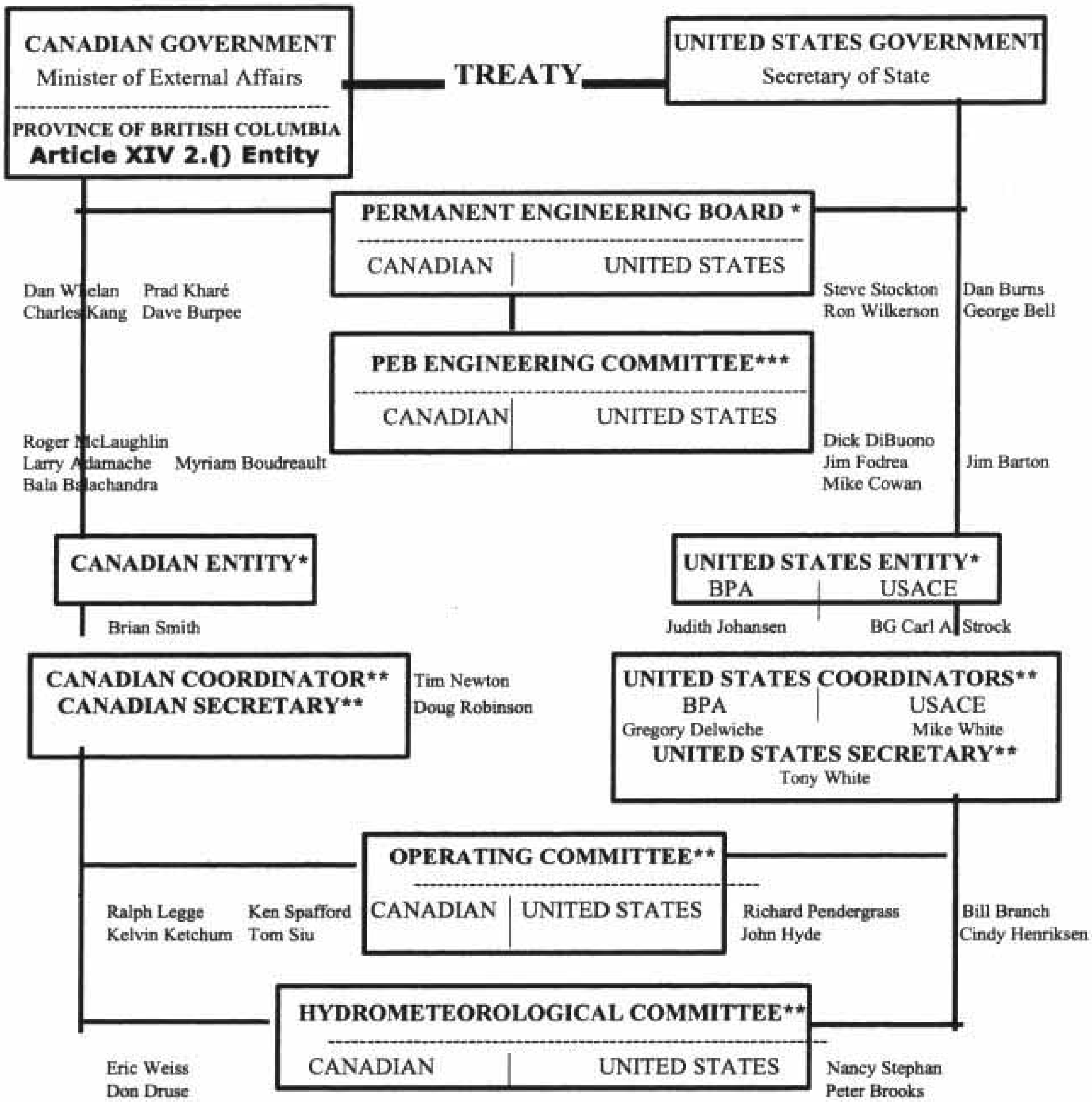
PEBCOM met with the Operating Committee on 27 October 1998 in Portland, Oregon and on 2 February 1999 in Vancouver, British Columbia.

International Joint Commission

The International Joint Commission (IJC) was created under the Boundary Waters Treaty of 1909 between Canada and the U.S. Its principal functions are rendering decisions on the use of boundary waters, investigating important problems arising along the common frontier not necessarily connected with waterways, and making recommendations on any question referred to it by either government. If the Entities or the PEB cannot resolve a dispute concerning the Columbia River Treaty, that dispute may be referred to the IJC for resolution.

The IJC has appointed local Boards of Control to insure compliance with IJC orders and to keep the IJC informed. There are three such boards west of the continental divide. These are the International Kootenay Lake Board of Control, the International Columbia River Board of Control, and the International Osoyoos Lake Board of Control. The Entities and the IJC Boards conducted their Treaty activities during the period of this report so that there was no known conflict with IJC orders or rules.

COLUMBIA RIVER TREATY ORGANIZATION



* ESTABLISHED BY TREATY
** ESTABLISHED BY ENTITY
*** ESTABLISHED BY PEB

III Operating Arrangements

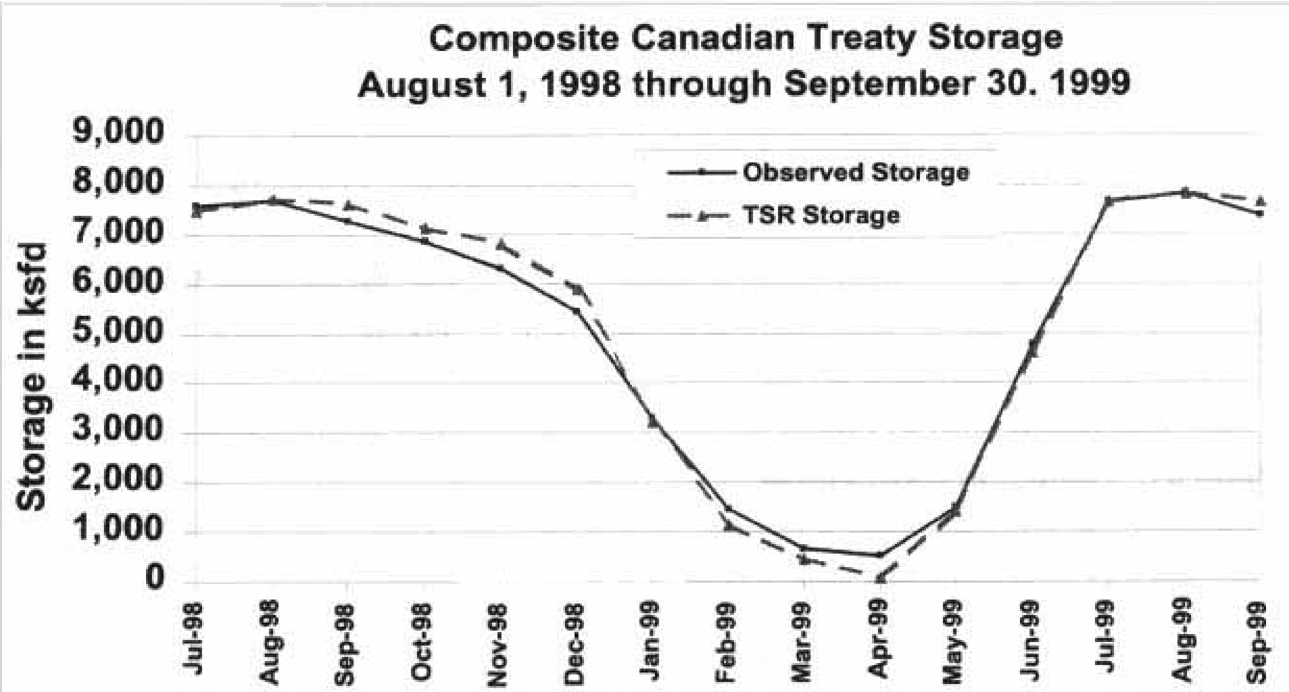
Power and Flood Control Operating Plans

The Columbia River Treaty requires that the reservoirs constructed in Canada be operated pursuant to flood control and hydroelectric operating plans developed thereunder. Annex A of the Treaty stipulates that the United States Entity will submit flood control operating plans (FCOP). Annex A also says that the Canadian Entity will operate in accordance with flood control storage diagrams or any variation which the Entities agree will not reduce the desired aim of the flood control plan. Annex A also provides for the development of hydroelectric operating plans six years in advance to furnish the Entities with an Assured Operating Plan (AOP) for Canadian storage. Article XIV.2.k of the Treaty provides that a Detailed Operating Plan may be developed to produce results more advantageous. The Protocol to the Treaty provides further detail and clarification of the principles and requirements of the Treaty.

The "Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans" dated December 1991 together with the "Columbia River Treaty Flood Control Operating Plan" dated October 1972, establish and explain the general criteria used to develop the DOP and operate Treaty storage during the period covered by this report. The flood control Storage Reservation Diagram for Libby contained in the 1972 Flood Control Plan, was amended by agreement of the Operating Committee to that contained in the USACE "Review of Flood Control, Columbia River Basin, Columbia River & Tributaries Study, CRT-63", dated June 1981.

The planning and operation of Treaty Storage as discussed on the following pages is for the operating year, 1 August through 31 July. The operation of Treaty storage is determined by the Treaty Storage Regulation (TSR). The TSR is developed based upon the critical rule curves and Power Discharge Requirements for all projects in the Pacific Northwest that were developed for the 1998-99 Assured Operating Plan (AOP). The resultant rule curves for Canadian projects may be updated slightly to be consistent with current requirements upon agreement of both Entities. The Canadian Storage operations resultant in the TSR are fixed and become input to the Pacific Northwest Coordination Agreement Actual Energy Regulation. The planning and operating for U.S. storage operated according to the Pacific Northwest Coordination Agreement which now utilizes the same period. U.S. storage projects operate to the principles defined in the Pacific Northwest Coordination Agreement procedures and the resultant Actual Energy Regulations (AER). Most of the hydrographs and reservoir charts in this report are for a thirteen-month period, July 1998 through July 1999.

The following chart compares the observed operation of the composite Canadian Treaty Storage to the results of the DOP Treaty Storage Regulation (TSR) study. The TSR was regulated to the Operating Rule Curve (ORC) during the entire period.



Assured Operating Plan

The Assured Operating Plans, dated October 1994 and November1994, established Operating Rule Curves and other operating criteria for Duncan, Arrow, and Mica during the 1998-99 and 1999-00 operating years, respectively. The Operating Rule Curves provided guidelines for draft and refill. They were derived from Critical Rule Curves, Assured Refill Curves, Upper Rule Curves, and Variable Refill Curves, consistent with flood control requirements, as described in the 1991 Principles and Procedures document. The Flood Control Storage Reservation Curves for all projects were established to conform to the Flood Control Operating Plan of 1972.

Determination of Downstream Power Benefits

For each operating year, the Determination of Downstream Power Benefits resulting from Canadian Treaty storage is made six years in advance in conjunction with the Assured Operating Plan.

For operating year 1999-00 the estimate of benefits resulting from operating plans designed to achieve optimum operation in both countries was less than that which would have prevailed from an optimum operation in the United States only. The Entities agreed that, in accordance with Sections 7 and 10 of the Canadian Entitlement Purchase Agreement (CEPA), the United States was entitled to receive:

- 3.7 average megawatts of energy and 0.4 megawatts of dependable capacity during the period 1 April 1998 through 31 March 1999, and
- 0.4 average megawatts of energy and no dependable capacity during the period 1 April 1999 through 31 March 2000

Suitable arrangements were made between the Bonneville Power Administration and B.C. Hydro for delivery of this energy, scheduled in accordance with the capacity provisions.

Return of Canadian Entitlement

Canadian Entitlement to downstream power benefits was sold in 1964 to a nonprofit organization, the Columbia Storage Power Exchange, under CEPA for a period of thirty years following completion of each Canadian storage project. Purchase of Entitlement under CEPA expired 31 March 1998 for Duncan, and 31 March 1999 for Arrow and will expire 31 March 2003 for Mica.

On 1 April 1998 Entitlement power began being returned to Canada at the U.S.-Canada border, over existing power lines, as established by the 20 November 1996 Entity Agreement. For the period 1 August 1998 through 31 March 1999, the amount returned for Duncan was 50.8 average megawatts of energy, scheduled at rates up to 136.8 megawatts. For the period 1 April 1999 through 31 July 1999, the amount returned for Duncan and Arrow was 308.6 average megawatts of energy, scheduled at rates up to 830.6 megawatts

Detailed Operating Plan

During the period covered by this report, the Operating Committee used the 1 August 1998 through 31 July 1999 "Detailed Operating Plan for Columbia River Treaty Storage" (DOP), dated August 1998 and the 1 August 1999 through 31 July 2000, DOP, dated June 1999, to guide storage operations. These DOP's established criteria for determining the Operating Rule Curves, proportional draft points, and other operating data for use in actual operations. The DOP used AOP loads and resources, and AOP rule curves for both Canadian and U.S. Projects to develop the Treaty Storage Regulation (TSR) study. The Variable Refill Curves and flood control requirements subsequent to 1 January 1999 were determined on the basis of seasonal volume runoff forecasts during actual operation. The Operating Committee directed the regulation of the Canadian storage, on a weekly basis throughout the year, in accordance with the applicable DOP's and operating agreements made thereunder.

Entity Agreements

During the period covered by this report, two joint U.S.-Canadian arrangements were approved by the Entities. The following tabulation indicates the date each of these were signed and gives a description of the agreement:

Date Agreement Signed by Entities	Description
29 March 1999	Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for 1 April 1998 through 15 September 2024, effective on 31 March 1999 with the exchange of diplomatic notes between the United States and Canada.
24 June 1999	Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for 1 August 1999 through 31 July 2000.

Operating Committee Agreements

During the period covered by this report, the Operating Committee approved four joint U.S.-Canadian agreements. The following tabulation indicates the dates they were signed, gives descriptions of the agreements, and cites the authority:

Date Agreement Signed by Committee	Description	Authority
1 December 1998	Columbia River Treaty Operating Committee Agreement on the Operation of TreatyStorage for Nonpower Uses for 1 January through 31 July 1999	Detailed Operating Plan, 1 August 1998 through 31 July 1999, approved 31 July 1998 and dated July 1998
22 December 1998	Agreement on Implementation of the Arrow Local Method for Treaty Storage For Operating Year 1998-99 Among the Columbia River Treaty Operating Committee, the Bonneville Power Administration, and the British Columbia Hydro and Power Authority	Detailed Operating Plan, 1 August 1998 through 31 July 1999, approved 31 July 1998 and dated July 1998
22 February 1999	Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for Enhancement of Mountain Whitefish Emergence for 1 February through 31 July 1999	Detailed Operating Plan, 1 August 1998 through 31 July 1999, approved 31 July 1998 and dated July 1998
24 August 1999	Columbia River Treaty Operating Committee Agreement on Operation of Treaty Storage for Enhancement of Mountain Whitefish Spawning for the Period 1 September 1999 through 30 April 2000	Detailed Operating Plan, 1 August 1999 through 31 July 2000, approved 24 June 1999 and dated June 1999

Long Term Non-Treaty Storage Contract

An Entity Agreement dated 9 July 1990 approved the contract between B.C. Hydro and BPA relating to the initial filling of non-Treaty storage, coordinated use of non-Treaty storage, and Mica and Arrow refill enhancement. The Operating Committee, in accordance with that agreement, monitored the storage operations made under this Agreement throughout the operating year to insure that they did not adversely impact operation of Treaty storage.

IV Weather and Streamflow

Weather

Late summer and fall of 1998 the weather was generally warm and drier than normal due to the presence of a high pressure ridge over the region. In November a typical winter-season low pressure system moved into the Gulf of Alaska producing a weather regime that sent a series of cooler and wetter storms over the Columbia Basin, a pattern that continued, with short interludes, throughout most of the operating year. In mid-December this pattern was first interrupted by a week-long outbreak of cold arctic air that cut off the moisture supply to the area. The wet pattern, with moderate rains and major snow accumulation, returned the last week of December and lasting through February, produced heavy snows in northern Idaho and western Montana. The westerly storm pattern from the Gulf low produced significant valley rainfall and mountain snowfall across most of the basin. Despite some seasonal warming, frequent winter-like storms with lingering valley rain and low elevation mountain snow continued during March. Seasonal snowpack accumulation is shown in Chart 1. Chart 3 illustrates the temperature and Precipitation Index above The Dalles during the winter season.

This weather pattern continued into early April with moderate precipitation occasionally reaching into the Idaho and western Montana. At mid-April a short warming reached northward into the upper Columbia basin and triggered snowmelt. The high pressure ridging which caused this interior warming was transient, however, and no sustained hot spell developed. Despite the erosion of the mid-elevation snowpack from normal seasonal warming, more widespread high elevation snow accumulation occurred in both early and late April.

May was generally cool with below normal precipitation although a short period of warm temperatures early in the month initiated the snowmelt, albeit at a slow pace. May began, however, with a series of Gulf of Alaska disturbances dominating the region which resulted in a continuation of the broad upper atmospheric pressure trough with moist unstable air circulating at the surface. This pattern brought rain to the valleys and late season snowfall to the mountains. After mid-month a high pressure ridge brought warmer southwest flow across the basin. Above normal temperatures on the east side of the Cascades helped invigorate the snowmelt process. Moderate streamflow rises were experienced in late May in the upper Columbia, Pend Oreille, east Kootenay, Spokane, and Okanagan areas.

During June an unseasonably low latitude jet stream brought minor disturbances from the Gulf of Alaska into the northern tier of the Pacific coastline making for a cooler month with wetter than normal periods. This dominant zonal weather pattern was briefly interrupted, first in mid June, by a period of strong high pressure ridging over the entire region, and then again late in the month when a vigorous low pressure from the Gulf brought significant rain to the western and northeastern portions of the basin.

Cooler and wetter than normal weather continued during July, with the exception of areas west of the Cascades and portions of southern Canada which were considerably wetter than normal. By mid-month the main jet stream retreated northward into southern Canada, and the basin began to experience some high pressure ridging over the Columbia Basin with the main trough centered off the Oregon Coast. This pattern continued to feed moist air into California, over Nevada, and into eastern Idaho and western Montana. Seasonal precipitation across the basin is shown in Chart 2. August continued the trend of moderate temperatures and rainfall, with most of the month's rainfall occurring mid-month during a week-long cold spell. The Temperature and Precipitation Index at The Dalles during the snowmelt season is shown in Chart 4, and the Temperature and Precipitation Index for Canada during the snowmelt season is shown in Chart 5.

1998-99 Precipitation Index at The Dalles, OR

Month	Precipitation		Month	Precipitation	
(1998)	(in.)	(%)	(1999)	(in.)	(%)
Jul	1.45	133	Jan	3.16	107
Aug	0.47	38	Feb	3.27	156
Sep	1.14	45	Mar	1.43	76
Oct	1.14	68	Apr	1.01	63
Nov	3.90	143	May	1.44	79
Dec	3.60	120	Jun	1.72	95
			Annual	23.75	102
			Jul	0.81	74
			Aug	1.51	122

Streamflow

The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 July 1998, through 31 July 1999, are shown on Charts 6 through 8. Chart 9 shows Libby hydrographs. Observed flows with the computed unregulated flow hydrographs for the same 13-month period for Kootenay Lake, Columbia River at Birchbank, Grand Coulee, and The Dalles are shown on Charts 10, 11, 12, and 13 respectively. Chart 14 is a hydrograph of observed and two unregulated flows at The Dalles during the April through July 1999 period, including a plot of flows occurring if regulated only by the Treaty reservoirs.

Composite operating year unregulated streamflows in the basin above The Dalles were above normal, and about 10 percent above last years average streamflows. July was the high month during the spring runoff, being in the 138 percent of normal range. The August 1998 through July 1999 runoff for The Dalles was 154 Maf, 113 percent of the 1961-90 average. The peak regulated discharge for the Columbia River at The Dalles was 379,300 cfs on 4 June 1999. The 1998-99 monthly unregulated (natural) streamflows and their percent of the 1961-90 average monthly flows are shown in the following table for the Columbia River at Grand Coulee and at The Dalles. These flows have been corrected to exclude the effects of regulation provided by storage reservoirs.

	Columbia River at Grand Coulee in cfs		Columbia River at The Dalles in cfs	
Time Period	Natural Flow	Percent of Average	Natural Flow	Percent of Average
Aug 98	107,630	103	137,870	100
Sep 98	85,780	133	96,160	100
Oct 98	32,280	67	67,350	78
Nov 98	38,590	80	84,380	91
Dec 98	41,570	98	101,470	108
Jan 99	46,950	114	121,720	124
Feb 99	48,270	104	120,330	104
Mar 99	74,810	127	189,160	134
Apr 99	127,660	110	252,270	112
May 99	246,460	94	421,090	100
Jun 99	375,640	114	596,130	120
Jul 99	261,290	136	356,300	138
Operating Year	123,910	110	212,020	113
Water Year	126,190	112	216,670	115

Seasonal Runoff Forecasts and Volumes

Observed 1999 April through August runoff volumes, adjusted to exclude the effects of regulation of upstream storage, are listed below for eight locations in the Columbia Basin:

Location	Volume In 1000 Acre-Feet	Percent of 1961-90 Average
Libby Reservoir Inflow	7,127	112
Duncan Reservoir Inflow	2,384	116
Mica Reservoir Inflow	12,414	108
Arrow Reservoir Inflow	26,049	112
Columbia River at Birchbank	48,249	119
Grand Coulee Reservoir Inflow	70,853	116
Snake River at Lower Granite Dam	27,277	119
Columbia River at The Dalles	110,336	118

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 1999 for a large number of locations in the Columbia River Basin and updated each month as the season advanced. Table 1 lists the April through August inflow volume forecasts for Mica, Arrow, Duncan, and Libby projects and for unregulated runoff for the Columbia River at The Dalles. Also shown in Table 1 are the actual volumes for these five locations. The forecasts for Mica, Arrow, and Duncan inflow were prepared by B.C. Hydro. The forecasts for the lower Columbia River and Libby inflows were prepared by the National Weather Service and River Forecast Center in cooperation with the Corps of Engineers, National Resource Conservation Service, Bureau of Reclamation and B.C. Hydro. The 1 April 1999, forecast of January through July runoff for the Columbia River above The Dalles was 128.0 Maf and the actual observed runoff was 124.1 Maf.

The following tabulation summarizes monthly forecasts since 1970 of the January through July runoff for the Columbia River above The Dalles compared with the actual runoff measured in millions of acre-feet (Maf). The average January-July runoff for the 1961-1990 period is 105.9 Maf.

The Dalles Volume Runoff Forecasts in Maf (Jan-Jul)

Year	Jan	Feb	Mar	Apr	May	June	Actual
1970	82.5	99.5	93.4	94.3	95.1		95.7
1971	110.9	129.5	126.0	134.0	133.0	135.0	137.5
1972	110.1	128.0	138.7	146.1	146.0	146.0	151.7
1973	93.1	90.5	84.7	83.0	80.4	78.7	71.2
1974	123.0	140.0	146.0	149.0	147.0	147.0	156.3
1975	96.1	106.2	114.7	116.7	115.2	113.0	112.4
1976	113.0	116.0	121.0	124.0	124.0	124.0	122.8
1977	75.7	62.2	55.9	58.1	53.8	57.4	53.8
1978	120.0	114.0	108.0	101.0	104.0	105.0	105.6
1979	88.0	78.6	93.0	87.3	89.7	89.7	83.1
1980	88.9	88.9	88.9	89.7	90.6	97.7	95.8
1981	106.0	84.7	84.5	81.9	83.2	95.9	103.4
1982	110.0	120.0	126.0	130.0	131.0	128.0	129.9
1983	110.0	108.0	113.0	121.0	121.0	119.0	118.7
1984	113.0	103.0	97.6	102.0	107.0	114.0	119.1
1985	131.0	109.0	105.0	98.6	98.6	100.0	87.7
1986	96.8	93.3	103.0	106.0	108.0	108.0	108.3
1987	88.9	81.9	78.0	80.0	76.7	75.8	76.5
1988	79.2	74.8	72.7	74.0	76.1	75.0	73.7
1989	101.0	102.0	94.2	99.5	98.6	96.9	90.6
1990	86.5	101.0	104.0	96.0	96.0	99.5	99.7
1991	116.0	110.0	107.0	106.0	106.0	104.0	107.1
1992	92.6	89.1	83.5	71.2	71.2	67.8	70.4
1993	92.6	86.5	77.3	76.6	81.9	86.1	88.0
1994	79.7	76.3	78.1	73.2	75.5	76.4	75.0
1995	101.0	99.6	94.3	99.6	99.6	97.9	104.0
1996	116.0	122.0	130.0	126.0	134.0	141.0	139.3
1997	138.0	145.0	142.0	149.0	153.0	159.0	159.0
1998	86.4	95.2	91.7	90.8	89.1	101.0	104.0
1999	116.0	119.0	130.0	128.0	124.0	123.0	124.1

V Reservoir Operation

General

The 1998-99 operating year began with below normal (66 percent to 76 percent of normal) precipitation in October across the basin. However, by the end of November precipitation had increased and the basin wide accumulated precipitation was at or above normal. The accumulated precipitation remained above normal through September. The January final water supply forecast, which was developed during the first ten days of January and included precipitation through 31 December, was 116 Maf at The Dalles for the January through July period. This was 110 percent of average for the period 1961-1990. February was a very wet month where precipitation was 137 percent of normal above Grand Coulee, 185 percent of normal above Lower Granite, and 156 percent of normal above The Dalles. When the March final water supply forecast was developed during the first ten days of March, this additional February precipitation was included. The March final water supply forecast increased to 130 Maf at The Dalles for the period January through July (123 percent of average). By the end of May, accumulative precipitation remained above normal, but not as high as in February. The June final water supply forecast was 123 Maf at The Dalles for the period January through July (116 percent of average). The observed runoff at The Dalles for the period January through July was 124 Maf, or 117 percent of average.

During the 3 April-31 August salmon flow augmentation period, U.S. projects were used to augment flows at Lower Granite and McNary. The National Marine Fisheries Service's Biological Opinion, released in early March 1995, listed objectives flows that were variable based on runoff volume forecasts. The objectives flows were:

- Lower Granite, 85,000-100,000 cfs during 10 April - 20 June, and 50,000-55,000 cfs during 21 June-31 August.
- McNary, 220,000-260,000 cfs during 20 April - June 30, and 200,000 cfs during 1 July-31 August.

Provision for adjusting flow objectives based on runoff volume forecastswas based on a sliding scale such that in 1999 Lower Granite flow objectives were at 100,000 cfs for the period 3 April – 20 June and 53,960 cfs for the period 21 June – 31 August. The McNary spring objective was 260,000 cfs for the period 20 April – 30 June. The summer objective was set at 200,000 cfs and does not vary with runoff forecasts.

The computation of the flow objectives at Lower Granite are based on the May final water supply forecast, which was 25.4 Maf at Lower Granite for the April through July period, which is 117 percent of average. The spring flow objective at McNary was based on the May final water supply forecast of 123 Maf at the Dalles for the January through July period. The flow objectives at Lower Granite were exceeded in the spring and summer. The observed outflow at Lower Granite for the period 3 April through 20 June was 114,000 cfs and 21 June to 31 August was 57,000 cfs. At McNary the Spring period flow objective was exceeded. The average observed outflow for the period 20 April through 30 June 30 was 302,000 cfs, and the observed flow from 1 July through 31 August was 233,000 cfs.

Canadian Treaty Storage Operation

As specified in the DOP, the release of Canadian Treaty storage is made effective at the Canadian-United States border. Accordingly, Mica releases can vary from the release specified to meet the TSR so long as this variance does not impact the ability of the Canadian system to deliver the sum of release from Arrow and Duncan required to meet the TSR. Variance from Treaty TSR releases are accumulated in respective Flex accounts. An overrun in an account occurs when actual project releases exceed those specified by the TSR. Conversely, an underrun occurs when actual project releases are below those specified by the TSR. Flex accounts for Mica, Revelstoke, Arrow, and Duncan are zero summed at any point in time to ensure that under/overruns do not impact the total Treaty release required at the Canadian-United States border. The terms under/overrun are used in the description of Mica Reservoir operations below.

Mica Reservoir

As shown in Chart 6, the Mica Reservoir (Kinbasket Lake) level was at elevation 2463.5 feet on 31 July 1998, 11.4 feet below full pool elevation of 2475 feet. The corresponding Mica Treaty storage account was 93 percent of full at 3284.0 ksfd (6.5 Maf) on that date.

The local inflows into Mica reservoir averaged about 35,000 cfs in August, reducing to 21,000 cfs in September and about 4.200 cfs by the end of December 1998. Mica Treaty storage continued to fill during August reaching full storage of 3529.2 ksfd (7.0 Maf) on 13 August 1998. The Mica Reservoir started to draft mid-September as turbine discharges exceeded inflows. The Mica Treaty underrun of 305 ksfd on 31 August was reduced in September, reaching a minimum of 5.6 ksfd on 30 October increasing again with a year end underrun at 171 ksfd on 31 December 1998.

Actual Mica discharges were fairly high through August 1998 and averaged 81 percent of the maximum turbine capacity. This corresponded to an average discharge of about 37,000 cfs in August. Subsequent discharges averaged about 30,000 cfs in September and in October, 22,000 cfs in November and about 26,000 cfs in December. Over November and December, the reservoir drafted by 25 feet to an elevation of 2417.8 feet by year end. At that time the B.C. Hydro Non-Treaty Storage was about 384 ksfd, or 34 percent of full, with Treaty storage at 2313.3 ksfd (4.6 Maf), or 65 percent of full.

In early January and February 1999, the inflows averaged about 4,000 cfs, gradually increasing in March to an average of about 5,000 cfs, and in April to 9,000 cfs before the start of the spring freshet in May. Mica powerhouse discharges for January and February averaged around 21 and 15,000 cfs, respectively, and the generation from Mica continued to decrease over winter 1999. The reservoir drafted by 32 feet during the period to elevation 2398.1 feet by 28 February with Treaty Storage at 1083.6 ksfd and Mica Treaty overrun of 130.7 ksfd on that date. The B.C. Hydro NTSA was at 595.4 ksfd at the end of February. During March and April, the Mica Reservoir was drafted by 24 feet and reached its lowest level for the 1998-99 year of 2373.5 feet on 20 April 1999, 12.9 feet lower than the low level in the previous year. Mica Treaty storage was drafted to zero Maf on 2 May with a Mica flex overrun of about 269 ksfd.

In March and April, the Mica turbine discharges averaged 23 and 18,000 cfs, respectively reducing to an average of about 8,000 cfs in May and 1,000 cfs in June 1999. The corresponding plant generation was 54 percent and 43 percent, respectively of plant capacity during March and April. With the start of the spring freshet in May, Mica discharges remained low until July, and the reservoir refilled by 52 feet to elevation 2426 feet at the end of June. At the end of May, the Mica Treaty underrun had increased to 391 ksfd. The Mica Treaty discharge was 10,000 cfs for the months of May, June and July, allowing Treaty storage to refill to 3369.5 ksfd (6.7 Maf; 95 percent of full) by 31 July. Local inflows peaked in May, June and July averaging about 22, 56 and 63,000 cfs, respectively. Actual Mica discharges during July averaged 7,000 cfs, resulting in a Mica Treaty underrun of 43 ksfd and a reservoir elevation of 2461.4 feet by end of July 1999. The corresponding plant generation was about 17 percent of plant capacity in July, 1999. The August inflows averaged about 55,000 cfs but started to recede and at month end, were about 47,000 cfs. The Mica Treaty storage reached full at 3529.2 ksfd on 10 August 1999 with the reservoir at 2469.4 feet, 5.6 feet below full pool. The Mica reservoir elevation at end of August 1999 was at 2474.6 feet (0.4 feet from full pool).

Revelstoke Reservoir

During the 1998-99 operating year, the Revelstoke project was operated generally as a run-of-river plant with the reservoir level maintained within 4.8 feet of its normal full pool elevation of 1880 feet. During the spring freshet, March through July, the reservoir operated as low as elevation 1875.1 feet to provide additional operational space to control high local inflows. Changes in Revelstoke storage levels did not affect Treaty storage operations.

Arrow Reservoir

As shown in Chart 7, the Arrow Reservoir level reached its maximum actual elevation of 1438.6 feet on 31 July with the Arrow Treaty storage reaching 100 percent full two days earlier on 29 July 1998. In comparison, the Mica Treaty storage filled on 13 August. The maximum Treaty storage from the Canadian Projects was recorded on 15 August 1998, at 7733.7 ksfd. The reservoir continued to draft in August and reached an elevation of 1433.2 feet by the end of September, 1.0 feet higher than the previous year. The Arrow Treaty storage was 6.3 Maf or 88 percent full at the end of September.

Arrow discharges decreased over the autumn months from an average of 50,000 cfs in September to 31,000 cfs in November. The discharge increased to an average of 40,000 cfs in December. Total inflows were 53.700 cfs in August, 40.600 cfs in September dropping to 31.700 cfs by the 1998 year-end, substantially lower than the previous year when the 1 in 200 year high rainfall event in October resulted in higher inflows late in the fall. The Arrow Reservoir drafted to elevation 1430.8 feet by 31 December 1998 with the Treaty storage at 2910 ksfd (5.7 Maf) or 81 percent of full on that date.

In late December 1998, B.C. Hydro requested that Arrow outflows be selectively reduced below TSR levels requests to keep river levels at acceptable and maintainable levels during the whitefish spawning and emergence period from 20 1998 December to 25 January 1999. To achieve the January level of flows, BC Hydro exercised an option to store up to 340 ksfd under the Whitefish Provisional Draft Agreement over the first 16 days of January. Subsequently, outflows from Arrow fluctuated around 45,000 cfs at Keenleyside, increasing in February to 90,000 cfs, and then reducing to about 40,000 cfs in March. The outflows from Arrow further reduced to 20,000 cfs on 25 March and continued at that level through April to meet objectives for rainbow trout spawning. In exchange for the rainbow trout protection flows in the spring, the U.S. had the option, under the Non-Power Uses agreement signed in December, to store up to 1 Maf in Arrow for Flow Augmentation objectives. Because of the unusually high volume runoff forecast, the U.S. Entity did not need to exercise this option. Arrow Reservoir continued to draft during the January to March period as local inflows averaged approximately 30,000 cfs.

In this operating year, the Columbia River Treaty Operating Committee agreed to use the 'Arrow Local Method' for determining the Mica and Arrow Variable Refill Curves between January and June 1999. Compared to the Total Method, the Arrow Local Method recognizes Mica outflows in excess of those from operating Mica to the Variable Refill Curve (VRC) when computing Arrow's VRC, and on average, results in lower VRC's at Arrow during January through April. In both cases, the Arrow reservoir is targeted to be full on 31 July. The Arrow Local Agreement was signed in December with the expectation that power benefits realized in excess of those expected by the Total Method would be shared equally between BPA and BC Hydro. Multi-year TSR studies have indicated that the expected power benefits occur during average-to-low water conditions, and as this operating year was an above average water year, there were no power benefits realized this year.

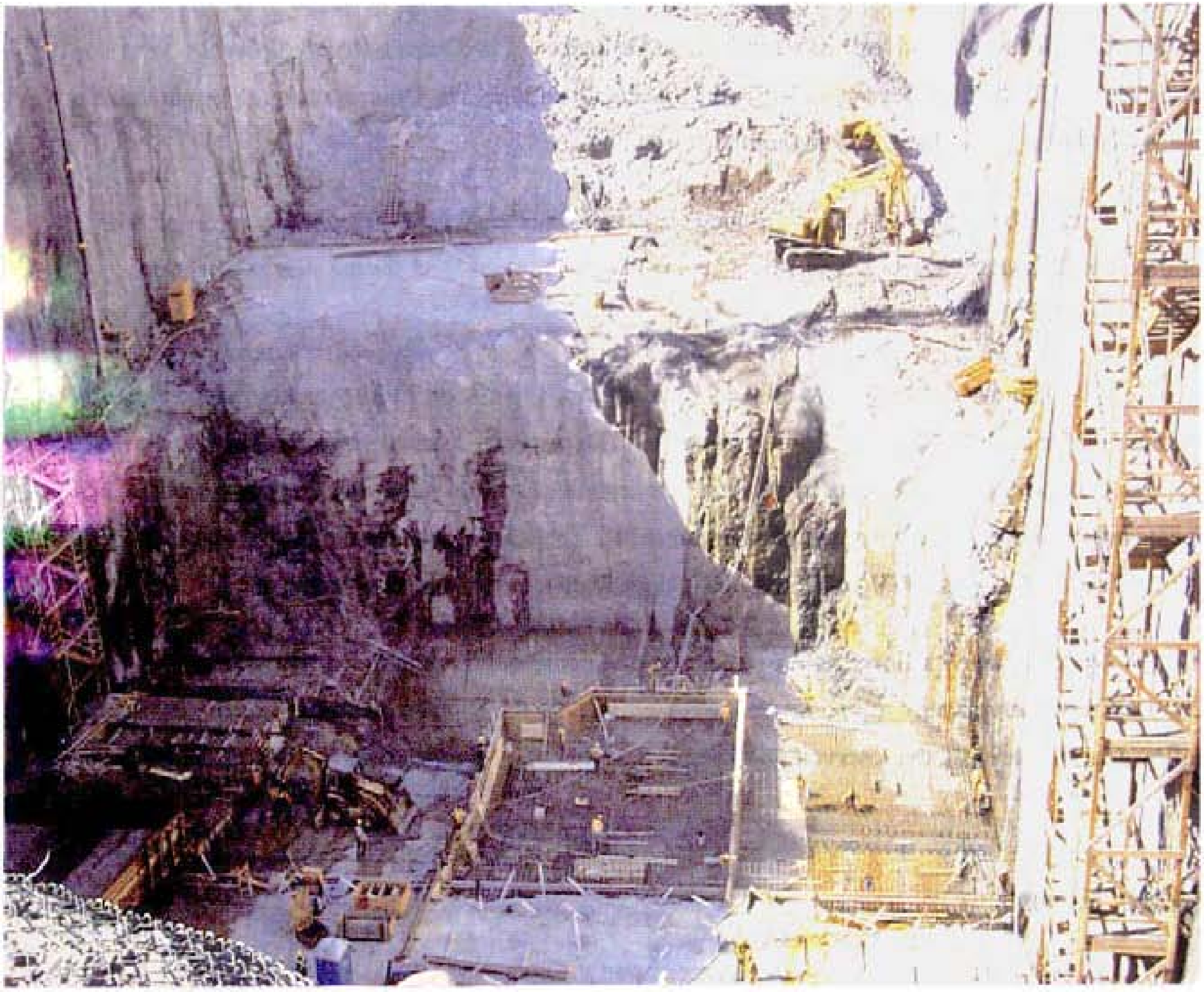
Arrow Reservoir reached its lowest level for the year at 1383.9 feet on 25 March 1999. Arrow Treaty storage account reached its minimum at 180 ksfd (0.35 Maf) or 5 percent of full on 24 March 1999. During April and early May, the Arrow discharge was maintained at about 20,000 cfs in an attempt to meet the objective that rainbow trout would not spawn at higher river levels. Arrow discharge on 12 May was set at 30,000 cfs and reduced further to 15,000 cfs during the last week of June when the backwater effects of higher Kootenay River flows provided adequate river levels for rainbow protection at Norns Creek Fan, a prime spawning location for rainbow trout Arrow discharge over the first week of July was reduced by about 20,000 cfs below TSR to reduce spill at Grand Coulee generating station in the U.S. In exchange, BPA agreed to open an additional 50 ksfd of Non-Treaty space above the 130 ksfd space required under the Recallable Account Agreement, by the end of July 1999

The Arrow fisheries operations were conducted under the terms of two Operating Committee agreements, "Operation of Treaty Storage for Enhancement of Mountain Whitefish Spawning for the period of 8 September 1998 through 31 July 1999" and "Operation of Treaty Storage for Nonpower Uses for 1 January through 31 July 1999". These agreements enabled the Arrow project flows to be adjusted to reduce impacts to whitefish and trout redds. With the low discharge in April and May, and the start of the spring freshet with high inflows in May, the Arrow Reservoir rose to elevation 1395.5 feet by 30 April, 1408.6 feet by 31 May, and 1434.5 feet by 30 June 1999. Arrow reservoir levels remained below the Treaty flood control curve levels throughout the operating year.

The Arrow discharge was increased substantially in July as Arrow Treaty storage neared full and the reservoir reached its highest elevation, 1443.8 feet, on 30 July 1999. The Arrow discharge peaked at 94.300 cfs on 11 August, approximately one week later than the previous year. The Arrow Treaty storage content continued to fill and reached full (7.1 Maf) on 31 July. Because of the unusually high July-August inflows, the Libby-Arrow storage exchange agreement used in prior operating years was not needed this year. Arrow Treaty content was full at the end of the August, but the actual reservoir operation drafted to elevation 1437.8 feet through the use of Mica/Arrow flexibility.

The Arrow Lakes Power Company project at Keenleyside received official 'leave to commence' for the start of construction 12 March 99. Preliminary preparation began in February 99, and full construction started on 15 March 99. During the week of 13 September 1999, forms for the draft tubes for the generating units were under construction as shown below.

Also shown during the week of 13 September 1999, excavation for the new powerhouse at Keenleyside Dam was well underway.



Duncan Reservoir

As shown in Chart 8, the Duncan reservoir level was at elevation 1892.1 feet, slightly above full pool on 13 August 1998. The reservoir level exceeded the full pool slightly for several days in August but remained within one foot of the full pool elevation of 1892.0 feet until 31 August 1998. The Duncan reservoir exceeded full Treaty storage on several days in August because of high inflows and then drafted to elevation 1877.9 feet by 30 September 1998. The Duncan reservoir essentially passed inflows in August 1998.

During the month of September, Duncan discharged an average of 7,000 cfs to maintain Kootenay Lake levels and Kootenay River flows. The project discharge averaged 9,000 cfs in October, 6,000 cfs in November and less than 1,000 cfs in December. The Duncan Reservoir level was at elevation 1830.7 feet (30 percent of full) on 31 December 1998. The Duncan reservoir remained at or below the flood control curve throughout the operating year.

During January, the Duncan discharge was increased to about 7 000 cfs. The reservoir was drafted throughout February to mid-March and reached its lowest level for the year at elevation 1794.4 feet (0.4 feet above empty) on 21 March 1999.

The Duncan discharge was reduced to minimum, 100 cfs, on 25 May and remained at that level during most of June to allow refill of the reservoir. The reservoir reached elevation 1814.7 feet by 31 May and elevation 1860.3 feet by 30 June. Duncan remained on minimum discharge until 20 July and increased thereafter to slow the rate of reservoir refill. The reservoir reached full pool elevation of 1892.0 feet on 3 August 1999, and exceeded it slightly on a number of days in August.

Duncan passed inflows for the remainder of August and through to the first week in September to maintain the reservoir near full pool. On 7 September 1999 the Duncan discharge was increased above inflows to start drafting the reservoir and keep Kootenay Lake elevation near the IJC limit.

Libby Reservoir

As shown in Chart 9, Lake Koocanusa started the operating year at elevation 2457.31 feet, within 2 feet of full pool. The lake reached it highest level of the summer on 16 July peaking at an elevation of 2458.33 feet, only 0.67 feet from full. The 1998 Libby/Arrow storage exchange agreement was implemented on 1 August which called for an exchange of as much as 200 ksfd of storage to bring Lake Koocanusa to an end of August elevation near 2448.0 feet. For the first few days of August, releases were held at 12,000 cfs in preparation of the 200 ksfd exchange. It was soon determined by the Canadian Entity that Arrow was drafting too quickly and the storage exchange of 200 ksfd was no longer desirable. The Libby/Arrow storage exchange target was reduced to 70 ksfd. In response to the new target, Libby releases were gradually ramped up from 12,000 cfs on 5 August to 22,000 cfs by 9 August. As hydrologic conditions at Arrow deteriorated the total amount of storage exchange fluctuated. By

23 August the U.S. and Canada agreed to exchange 107 ksfd of storage in Libby which would bring the end of August target elevation near elevation 2444 feet. The U.S. Salmon Managers requested to have all water released from Libby prior to the end of August to ensure that it would travel past McNary Dam before 31 August 1998. In response to this request, outflow from Libby was ramped down slowly over a six-day period from 22,000 to 9,900 cfs by 28 August.

Outflow from Libby was increased to 14,900 cfs 2 September through 5 September to meet power demands. After the power demand had waned the outflow was 9,900 cfs for 5 days and then 8,000 cfs for the remainder of September and for the first half of October. In October, outflows were reduced to 6,000 cfs over 3 days. The reduction in releases was requested by Bonneville Power Administration (BPA) and releases were held through mid-November. A further reduction was requested by BPA in November to hold releases at the minimum outflow of 4,000 cfs. From 1 December through 18 December daily load shaping occurred on weekdays and weekend flows were held steady at 10,000 cfs. By 20 December the Pacific Northwest was experiencing a cold snap. In response to meet regional load, the Libby outflow was increased to full powerhouse capacity by 21 December, where it remained for three days. Outflow was reduced slightly over the Holiday weekend, since the cold snap had diminished. From 28 through 31 December the Libby outflow was approximately 21,000 cfs as the project was used to meet load. The monthly average outflow in December was 19,100 cfs. The end of December elevation at Lake Koocanusa was 2405.6 feet, 5.4 feet below the normal 31 December flood control elevation of 2411 feet.

The water supply forecasts at Libby in January through March generally increased with time. In January the April through August forecast was 6.63 Maf, or 104.0 percent of average. In February and March the forecasts were 108.6 percent and 111.2 percent of average, respectively. In April and May the forecasts dropped again and were 109.1 percent and 105.6 percent, respectively. The end of month flood control targets at the end of each month were: January, elevation 2375.7 feet; February, elevation 2333.8 feet; March, elevation 2310.9 feet; and April, elevation 2339.8 feet.

In January outflows ranged between 21,500 and 26,000 cfs between 1 January and17 January. Starting on 18 January flows were reduced gradually to 6,000 cfs to provide Idaho Department of Fish and Game a chance to monitor burbot movement below Libby. Flows were increased again on 25 January. The end of January elevation was 2373.9 feet, or within 1.8 feet of the flood control target. The February average outflow was 21,100 cfs, and the end of month elevation was 2334.14 feet, within 0.3 feet of the flood control target. Between 1 March and 8 March there were four units available and these units were run at full load, approximately 16,400 cfs. Between 9 and 11 March, the outflow was reduced to 4,000 cfs to target the April 15th 95 percent confidence of refill curve near elevation 2326 feet. However, the March and April average inflow was less than 4,000 cfs, and Libby was below the April 15th 95 percent confidence of refill curve as expected. The end of March elevation was 2323.46 feet, or 12.6 feet above the end of March target flood control elevation. The April average outflow was 4,000 cfs, and the end of month elevation was 2338.56 feet, within 1.2 feet of the flood control target. Flows were held at 4,000 cfs through May in preparation for the sturgeon pulse request from USFWS. The end of May elevation was 2386.56 feet.

Outflows were maintained at 4,000 cfs through 13 June at which time the sturgeon pulse was requested by USFWS. The 1999 pulse was much later than normal because of low water temperatures at Bonners Ferry. The Libby outflow was 25,000 cfs 15 June through 18 June. After the pulse, incubation flows were held at 30,000 cfs measured at Bonners Ferry for 18 days. Outflows from Libby ranged from 16,800 to 25,000 cfs to provide the incubation flows downstream. Lake Koocanusa was at elevation 2432.94 feet on 30 June, and these higher flows ended 5 July when Libby outflows were gradually ramped down to 8,000 cfs by 10 July. Libby outflows of 8,000 cfs were held for the majority of July and Lake Koocanusa filled to an end of month elevation of 2456.94 feet, within 2.1 feet from full.

Libby inflows in August were considerable at 151 percent of normal, the third highest for the period 1928-1988. Outflows ranged from 8,000 to 22,600 cfs to keep the project from filling and spilling. A peak reservoir elevation was reached on 9 August of 2458.97 feet, essentially a full pool. A 1999 Libby/Arrow storage exchange agreement was not entered into. Due to the abundance of water in the Columbia Basin system the resulting end of month elevation in August was 2455.63 feet, 3.37 feet from full and 16.63 feet above the 1995 Biological Opinion interim draft limit of elevation 2439 feet.

For the majority of September 1999, outflows were held steady at 12,000 cfs as the project began a slow draft to the 31 December flood control elevation of 2411.0 feet. Outflows were reduced to 10,000 cfs on 16 September for transmission line testing, and releases were brought back to 12,000 cfs for the remainder of the month. Lake Koocanusa ended the month of September at elevation 2449.12 feet, 9.88 feet from full.

Kootenay Lake

As shown in Chart 10, the level of Kootenay Lake at Queens Bay was at elevation 1743.8 feet on 31 July 1998. The reservoir level fluctuated gradually between 1743.5 feet to 1744.8 between August 1998 and early January 1999 and remained below the IJC maximum elevation of 1745.32 feet effective 1 September 1998 until 7 January 1999. Essentially, the Duncan reservoir was drafted from September to mid November to keep the Kootenay lake elevation close to the IJC level.

For the month of September, the Kootenay Lake discharge was adjusted to keep the downstream Brilliant plant at full load without spill at approximately 19,000 cfs. The reservoir level was raised in September, as allowed in the IJC Order, and reached a maximum elevation of 1744.8 feet on 16 December, 1998. During October and November, the reservoir level was kept high by passing inflow, with year-end elevation of 1743.5 feet on 31 December 1998. The reservoir did not reach the maximum IJC elevation of 1745.32 feet through to 7 January 1999.

Beginning in January, the Kootenay Lake level rose initially and then reduced to 1743.5 feet by month end. The reservoir discharges were kept slightly above the inflows during February-March to stay below the IJC limits. The reservoir level at the end of March 1999 was 1739.5 feet. The reservoir reached a minimum level of 1738.4 feet on 17 April 1999, rising quickly thereafter with the commencement of the spring freshet. The inflows peaked on 17 June at 112,000 cfs. The Kootenay reservoir discharges were then also increased, and the outflows from Duncan reduced to minimum, to reduce the Kootenay reservoir level rise in the summer of 1999. Kootenay Lake discharges peaked on 25 June at 71.800 cfs.

Kootenay Lake reached its peak level for the year at elevation 1750.2 feet on 26 June 1999 about three weeks later than the previous year. The reservoir level gradually started to recede due to receding runoff in late June and in July, and due to reduced Libby discharges in July 1999. Kootenay Lake drafted in these months with the lowest summer reservoir elevation of 1745.0 feet occurring on 31 August. Discharge from Kootenay Lake averaged 50,000 cfs in July and 38,000 cfs in August 1999. The Nelson gauge level remained above the IJC summer level elevation of 1743.32 feet as of 16 September 1999. During August, increased outflows from Libby and Duncan served the strong market demand and caused the reservoir to draft gradually. This, combined with operational adjustments, allowed the reservoir level to maintain operating space in September, to accommodate unit outages at Kootenay projects in the fall.

VI Power and Flood Control Accomplishments

General

During the period covered by this report, Duncan, Arrow, and Mica reservoirs were operated for power, flood control, and other benefits in accordance with the Columbia River Treaty and operating plans and agreements described in Section III. Consistent with all DOP's prepared since the installation of generation at Mica, the 1998-99 and 1999-00 DOP's were designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States, in accordance with paragraph 7 of Annex A of the Treaty.

During the period covered by this report, Libby reservoir was operated for flood control and other purposes in accordance with the Treaty and the 1972 "Columbia River Treaty Flood Control Operating Plan," as amended by the U.S. Army Corps of Engineers (USACE) "Review of Flood Control, Columbia River Basin, Columbia River & Tributaries Study, CRT-63", dated June 1981. During a portion of the year, Libby operated for power purposes according to the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER). During the remainder of the operating year, Libby operated for storage and releases recommended for endangered white sturgeon and salmon by the USFWS and the U.S. National Marine Fishery Service Biological Opinions. As recorded in the Detailed Operating Plan for the current year, the Entities could not agree on operations of Libby project.

Flood Control

The Columbia River Basin reservoir system, including the Columbia River Treaty projects, was not operated for flood control during the 1998-1999 winter period, and although there were no daily requests made for flood control, the weekly agreed-to operations were adequate to accomplish spring flood evacuation control goals. The weekly operation was guided to a large extent by the daily streamflow and reservoir simulations and to a lesser degree by the charts in the Flood Control Operating Plan. Early on there was a modest potential for flooding, but favorable weather conditions in June moderated runoff to the point that the reservoir system had an easy task in controlling river flows to desirable levels. The unregulated flow at The Dalles, Oregon, shown on chart 14, is estimated at 712,000 cfs on 20 June and a regulated flow of 379,000 cfs on 4 June. The unregulated stage at Vancouver, Washington was 24.1 feet on 21 June and the high-observed stage was 12.4 feet on 28 May.

Chart 15 shows the relative filling of Arrow and Grand Coulee during the filling period and compares the regulation to guide lines, chart 6, of the Columbia River Treaty Flood Control Operating Plan. Because this years runoff volume was forecast to be moderately above normal, 116 percent, and Mica having drafted very deep for power, there was no daily operations specified for Arrow, and they were allowed to meet their fish flow objectives and accomplish the flood control objectives.

Computations of the Initial Controlled Flow (ICF) for system flood control operation were made in accordance with the Treaty Flood Control Operating Plan. Computed Initial Controlled Flows at The Dalles were 390,000 cfs on 1 January 1999, 398,000 cfs on 1 February, 451,000 cfs on 1 March, 434,000 cfs on 1 April, and 416,000 cfs on 1 May. As mentioned earlier, the observed peak flow at The Dalles was 379,000 cfs on June 4. Data for the 1 May ICF computation are given in Table 6.

Canadian Entitlement

The Canadian Entitlement to downstream power benefits from Duncan, Arrow and Mica for most of 1998-99 operating year had been purchased in 1964 by the Columbia Storage Power Exchange (CSPE). The sale of the Canadian Entitlement to downstream power benefits from the operation of Duncan reservoir and Arrow reservoir terminated on 31 March 1998 and 31 March 1999, respectively. In accordance with the Canadian Entitlement Exchange Agreement dated 13 August 1964, the U.S. Entity delivered capacity and energy to the CSPE participants. Delivery under the Canadian Entitlement Exchange, was 215 average megawatts from 1 August 1998 through 31 March 1999 and 103 average megawatts from 1 April 1999 through 31 July 1999. Capacity provisions supported scheduled deliveries up to 416 megawatts from 1 August 1998 through 31 March 1999 and 200 megawatts from 1 April 1999 through 31 July 1999.

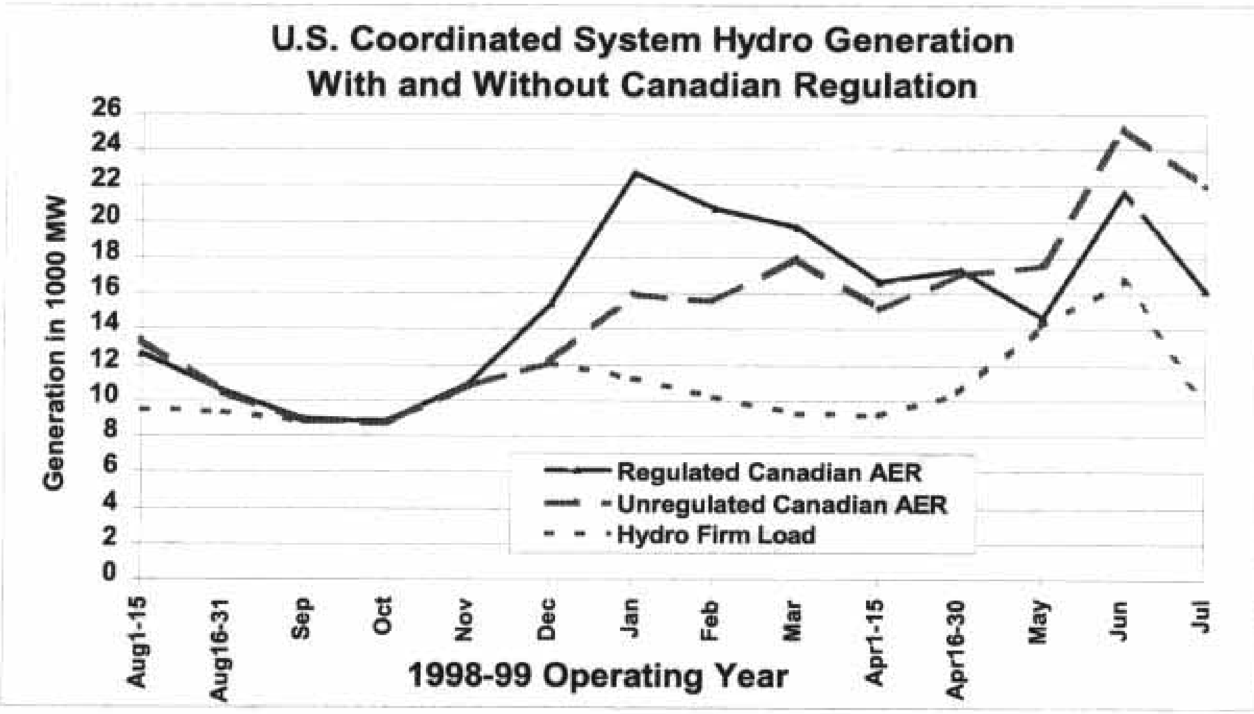
In accordance with the Entity Agreement on the Determination of Downstream Power Benefits for Operating Year 1998-99, the Canadian Entity delivered to the U.S. Entity 3.7 average megawatts of annual energy and 0.4 MW of dependable capacity during the period 1 August 1998 through 31 March 1999. In accordance with the Entity Agreement on the Determination of Downstream Power Benefits for Operating Year 1999-00, the Canadian Entity delivered to the U.S. Entity 0.4 average megawatts of annual energy and no dependable capacity during the period 1 April 1999 through 31 July 1999. These energy deliveries were required by Section 7 of the August 1964 Canadian Entitlement Purchase Agreement.

From 1 August 1998 through 31 March 1999, the U.S. Entity delivered the Canadian Entitlement to downstream power benefits from the operation of Duncan reservoir to the Canadian Entity, at existing points of interconnection on the Canada-U.S. border. The amount returned, not including transmission losses and scheduling adjustments, was 50.8 average MW at rates up to 136.8 MW. The Canadian Entitlement returned to the Canadian Entity for the operation of Duncan and Arrow reservoirs, during the period 1 April 1999 through 31 July 1999, was 308.6 average MW at rates up to 830.6 MW. On 1 August 1999, the Canadian Entitlement return decreased slightly to 306.8 average MW at rates up to 801.7 MW.

On 31 March 1999, a diplomatic exchange of notes between Canada and the United States, envisioned in the Treaty by Article VIII, Section 1, adopted a disposal agreement permitting disposal of Entitlement directly in the United States. The exchange, subsequently ratified by Canadian Parliament, also designated the Province of British Columbia as a Canadian Entity for the sole purpose of the Treaty's Article XIV, Section 2(i).

Power Generation and Other Accomplishments

The Coordinated System storage level at the beginning of the 1998-99 operating year was 99.39 percent full as of 31 July 1998 as measured in the Pacific Coordination Agreement (PNCA) Actual Energy Regulation (AER). The Treaty Storage operation in the AER is fixed from the TSR study. Since the system was 99.39 percent full, 1st-year firm energy load carrying capability (FELCC) was adopted for the U.S. system from the PNCA critical period studies. Due to above average streamflows throughout the year, the system generally operated to Operating Rule Curve (ORC) or flood control for the entire period, producing large amounts of surplus energy. The system storage energy reached 99.87 percent full on 31 July 1999, as measured in the AER, and the system adopted 1st-year FELCC from the 1999-00 PNCA Final Regulation study. Actual U.S. power benefits from the operation of Treaty storage are unknown due to the complicated nature of hourly power operations and the need to speculate on alternative operating procedures, nonpower requirements, and market conditions in the absence of Treaty storage. However, the following graph shows a rough estimate of the average monthly impact on downstream U.S. power generation during the 1998-99 operating year, with and without the regulation of Canadian Treaty storage, based on the PNCA AER that includes minimum flow and spill constraints for U.S. fishery objectives. The U.S. gain in average annual generation was 432 MW, but the gain in average annual usable energy (computed similar to the Treaty downstream power benefit computation as firm energy, plus non-firm energy that displaces AOP thermal resources, plus 40 percent of the remaining nonfirm energy) was only 354 MW. The sharp decrease from last year's 1022 MW increase in usable

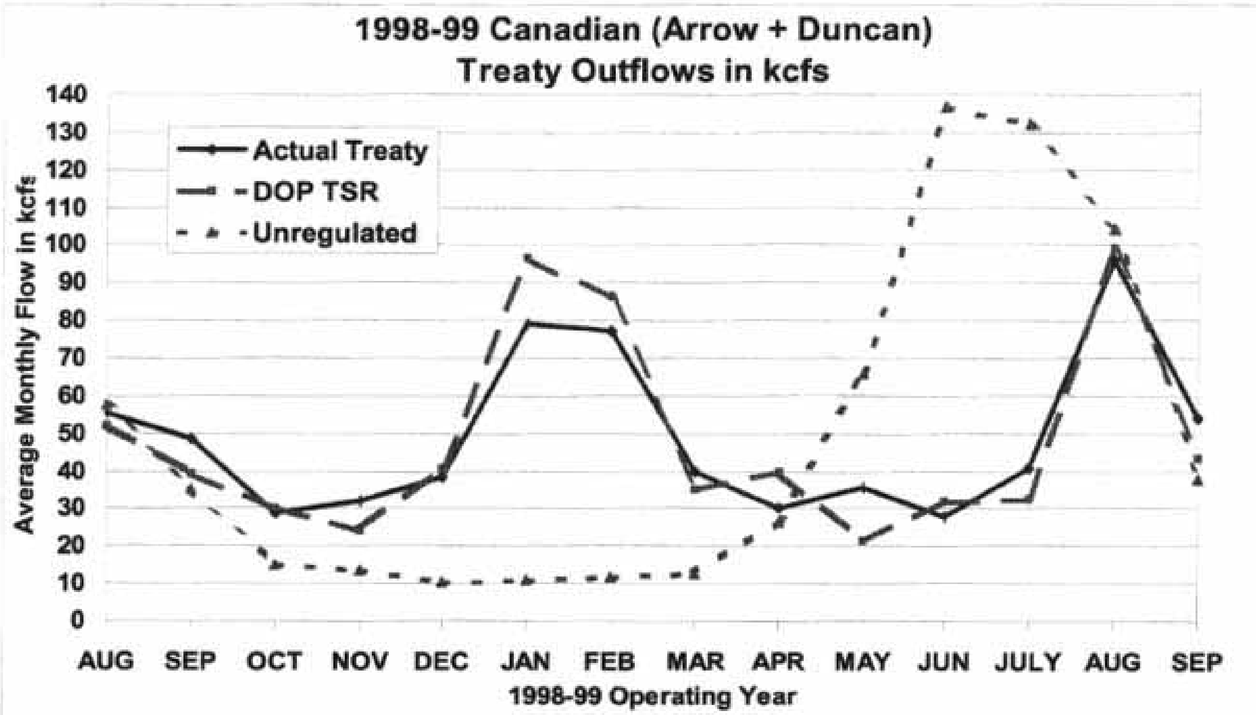


energy was caused by the very high inflows during the 1998-99 operating year, which reduces the need for Canadian storage for power benefits.

Based on the authority from the 1998-99 and 1999-00 DOP's, the Operating Committee completed several operating agreements, described in Section III, that resulted in power and other benefits both in Canada and the U.S. Other benefits include increased reservoir levels for summer recreation and dust storm avoidance and changes to streamflows below Arrow that enhanced trout and white fish spawning and the downstream migration of salmon. The graph below shows the difference in Arrow plus Duncan average monthly regulated outflows between the DOP TSR and the actual Treaty flows due to these agreements. The unregulated stream flows are also shown for comparison purposes.

As of 30 September 1998, the sum of Canadian Treaty storage was positioned 312 ksfd below the DOP TSR. The Entities had drafted a total of 107 ksfd below the TSR by 31 August 1998, per the terms of the Arrow/Libby Swap Agreement, and the U.S. provisionally drafted 205 ksfd in September under the Libby provisional draft agreements.

In early October 1998, the U.S. provisionally drafted an additional 35 ksfd from Arrow to increase the forebay of Grand Coulee. In the first half of November 1998, the US again scheduled provisional draft such that the sum of Canadian Treaty storage was positioned 417 ksfd below the DOP TSR. During mid November, the US returned half of the provisional draft (40 ksfd) and their half of the Libby/Arrow Swap. In late November and early December, the US exhausted its provisional draft accounts by drafting 110 ksfd. On 31 December 1999 Canadian Treaty storage was positioned 434 ksfd below the DOP TSR.



Beginning January 1999, Arrows discharge was again reduced below TSR levels per the terms of the Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for the Enhancement of Mountain Whitefish Spawning for 8 September 1998 through 30 April 1999. Due to the high runoff year, storage above the DOP TSR for U.S. flow augmentation was not required. During February, deep Canadian and U.S. reservoir drafts for power and flood control requirements provided an opportunity for Canada and the U.S. to provisionally store 285 ksfd under the Agreement for Enhancement of Mountain Whitefish Emergence. Canada released one-half of this storage in March to augment flows in BC for whitefish emergence and the U.S. released the other half in April and May for U.S. for power production.

During the April through July 1999 period, water was stored and released in a manner consistent with Canada's need for trout spawning and progressive Arrow refill consistent with U.S. flood control requirements. By July 1999, Canadian storage was returned to its TSR elevation.

Table 1

Unregulated Runoff Volume Forecasts

Million of Acre-Feet

1999

Forecast Date - 1st of	Duncan Most Probable 1 April - 31 August	Arrow Most Probable 1 April - 31 August	Mica Most Probable 1 April - 31 August	Libby Most Probable 1 April - 31 August	Columbia River at The Dalles, Oregon Most Probable 1 April - 31 August
January	2.02	25	11.7	6.62	102
February	2.15	26.1	12.0	6.92	104
March	2.26	26.9	12.3	7.09	115
April	2.32	26.1	12.2	6.95	112
May	2.33	25.9	12.3	6.76	108
June	2.27	25.4	12.1	6.58	108
Actual	2.0	20.8	11.0	7.13	110.3

NOTE: These data were used in actual operations. Subsequent revisions have been made in some cases.

TABLE 2

1999 Variable Refill Curve

Mica Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW,KAF			9701.3	9879.8	9907.6	9614.0	9100.3	7733.7
PROBABLE DATE-31JULY INFLOW,KSFD	**		4891.0	4981.0	4995.0	4847.0	4588.0	3899.0
95% FORECAST ERROR FOR DATE, KSFD			653.0	510.4	465.4	444.5	360.5	360.5
95% CONF.DATE-31JULY INFLOW,KSFD	1/		4238.0	4470.6	4529.6	4402.5	4227.5	3538.5
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		4238.0					
FEB MINIMUM FLOW REQUIREMENT,CFS	3/		3000.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	4/		1427.5					
MIN JAN31 RESERVOIR CONTENT,KSFD	5/		718.7					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		2411.4					
JAN31 ECC,FT.	7/		2417.0					
BASE ECC, FT		2451.7						
LOWER LIMIT,FT		2417.0						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.6	97.6				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		4136.3	4363.0				
MAR MINIMUM FLOW REQUIREMENT,CFS	3/		3000.0	3000.0				
MIN MAR1-JUL31 OUTFLOW,KSFD	4/		1343.5	1343.5				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		736.4	509.4				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		2411.9	2406.6				
FEB28 ECC,FT.	7/		2411.9	2406.6				
BASE ECC,FT		2441.8						
LOWER LIMIT,FT		2405.1						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			95.1	95.1	97.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		4030.3	4251.5	4411.8			
APR MINIMUM FLOW REQUIREMENT,CFS	3/		3000.0	3000.0	3000.0			
MIN APR1-JUL31 OUTFLOW,KSFD	4/		1250.5	1250.5	1250.5			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		749.4	528.2	367.9			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		2412.2	2407.0	2403.2			
MAR31 ECC,FT.	7/		2412.2	2407.0	2403.2			
BASE ECC,FT		2430.7						
LOWER LIMIT,FT		2395.5						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			90.0	90.0	92.2	94.7		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		3814.2	4023.5	4176.3	4169.1		
MAY MINIMUM FLOW REQUIREMENT,CFS	3/		3000.0	3000.0	3000.0	3000.0		
MIN MAY1-JUL31 OUTFLOW,KSFD	4/		1100.5	1100.5	1100.5	1100.5		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		815.5	606.2	453.4	460.6		
MIN APR30 RESERVOIR CONTENT,FEET	6/		2413.7	2408.8	2405.2	2405.4		
APR30 ECC,FT.	7/		2413.7	2408.8	2405.2	2405.4		
BASE ECC,FT		2420.8						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			71.6	71.6	73.3	75.3	79.5	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		3034.4	3200.9	3320.2	3315.1	3360.9	
JUN MINIMUM FLOW REQUIREMENT,CFS	3/		10000.0	10000.0	10000.0	10000.0	10000.0	
MIN JUN1-JUL31 OUTFLOW,KSFD	4/		945.5	945.5	945.5	945.5	945.5	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		1440.3	1273.8	1154.5	1159.6	1113.8	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		2427.7	2424.0	2421.4	2421.5	2420.5	
MAY31 ECC,FT.	7/		2425.0	2424.0	2421.4	2421.5	2420.5	
BASE ECC,FT		2425.0						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			35.5	35.5	36.3	37.3	39.4	49.5
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		1504.5	1587.0	1644.2	1642.1	1665.6	1751.6
JUL MINIMUM FLOW REQUIREMENT,CFS	3/		10000.0	10000.0	10000.0	10000.0	10000.0	10000.0
MIN JUL1-JUL31 OUTFLOW,KSFD	4/		480.5	480.5	480.5	480.5	480.5	480.5
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		2505.2	2422.7	2365.5	2367.6	2344.1	2258.1
MIN JUN30 RESERVOIR CONTENT,FEET	6/		2450.1	2448.4	2447.2	2447.3	2446.8	2445.0
JUN30 ECC,FT.	7/		2449.2	2448.4	2447.2	2447.3	2446.8	2445.0
BASE ECC,FT		2449.2						
JUL 31 ECC, FT			2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (3529.2 KSFD) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.A143
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.

TABLE 3

1999 Variable Refill Curve

Arrow Reservoir

		INITIAL	JAN 1 Local	FEB 1 Local	MAR 1 Local	APR 1 Local	MAY 1 Local	JUN 1 Local
PROBABLE DATE-31JULY INFLOW,KAF			11526.1	12214.4	12456.4	11988.3	10835.9	8610.4
& IN KSFD	**		5811.0	6158.0	6280.0	6044.0	5463.0	4341
95% FORECAST ERROR FOR DATE,IN KSFD			762.0	632.8	505.1	403.5	341.6	341.6
95% CONF.DATE-31JULY INFLOW,KSFD	1/		5049.0	5525.2	5774.9	5640.5	5121.4	3999.4
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		5049.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	3/		2828.0					
UPSTREAM REFILL,KSFD	4/		3179.0					
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		0.0					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		1377.9					
JAN31 ECC,FT.	7/		1403.4					
BASE ECC, FT		1413.6						
LOWER LIMIT, FT		1403.4						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.3	97.3				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		4912.7	5376.0				
MIN MAR1-JUL31 OUTFLOW,KSFD	3/		2688.0	2688.0				
UPSTREAM REFILL,KSFD	4/		2451.0	2544.9				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		0.0	0.0				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		1377.9	1377.9				
FEB28 ECC,FT.	7/		1385.2	1385.2				
BASE ECC, FT		1400.6						
LOWER LIMIT, FT		1385.2						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			93.9	93.9	96.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		4741.0	5188.1	5567.0			
MIN APR1-JUL31 OUTFLOW,KSFD	3/		2533.0	2533.0	2533.0			
UPSTREAM REFILL,KSFD	4/		1614.0	1707.9	1816.3			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		0.0	0.0	0.0			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		1377.9	1377.9	1377.9			
MAR31 ECC,FT.	7/		1377.9	1377.9	1377.9			
BASE ECC,FT		1401.4						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			85.3	85.3	87.6	90.9		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		4306.8	4713.0	5058.8	5127.2		
MIN MAY1-JUL31 OUTFLOW,KSFD	3/		2383.0	2383.0	2383.0	2383.0		
UPSTREAM REFILL,KSFD	4/		995.7	1076.7	1199.2	1183.9		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		660.1	172.9	0.0	0.0		
MIN APR30 RESERVOIR CONTENT,FEET	6/		1392.8	1382.1	1377.9	1377.9		
APR30 ECC,FT.	7/		1392.8	1382.1	1377.9	1377.9		
BASE ECC, FT		1406.2						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			59.9	59.9	61.5	63.8	70.2	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		3024.4	3309.6	3551.6	3598.6	3595.2	
MIN JUN1-JUL31 OUTFLOW,KSFD	3/		2135.0	2135.0	2135.0	2135.0	2135.0	
UPSTREAM REFILL,KSFD	4/		685.7	766.7	889.2	873.9	871.8	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		2004.5	1638.3	1273.8	1242.1	1247.6	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		1418.4	1411.8	1405.0	1404.4	1404.5	
MAY31 ECC,FT.	7/		1418.4	1411.8	1405.0	1404.4	1404.5	
BASE ECC,FT		1418.6						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			25.6	25.6	26.3	27.3	30.0	42.7
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		1292.6	1414.4	1518.8	1539.9	1536.4	1707.7
MIN JUL1-JUL31 OUTFLOW,KSFD	3/		1085.0	1085.0	1085.0	1085.0	1085.0	1085.0
UPSTREAM REFILL,KSFD	4/		385.7	466.7	589.2	573.9	571.8	548.3
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		2986.3	2783.5	2556.6	2550.8	2556.4	2408.6
MIN JUN30 RESERVOIR CONTENT,FEET	6/		1434.8	1431.5	1427.8	1427.7	1427.8	1425.3
JUN30 ECC,FT.	7/		1434.8	1431.5	1427.8	1427.7	1427.8	1425.3
BASE ECC,FT		1436.1						
JUL 31 ECC, FT			1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ CUMMULATIVE MINIMUM OUTFLOW FROM DATE TO JULY, USING POWER DISCHARGE REQUIREMENTS
4/ UPSTREAM DISCHARGE REQUIREMENT. 5/ FULL CONTENT(3579.6 KSFD) MINUS 2/ PLUS 3/ MINUS /4.
6/ ELEV. FROM 5/, INTERP. FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR ELEV DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.

TABLE 4

1999 Variable Refill Curve

Duncan Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW,KAF			1733.6	1858.5	1904.2	1912.1	1783.2	1384.5
& IN KSFD	**		874.0	937.0	960.0	964.0	899.0	698.0
95% FORECAST ERROR FOR DATE,IN KSFD			118.4	108.9	97.5	88.1	73.3	73.3
95% CONF.DATE-31JULY INFLOW,KSFD	1/		755.6	828.1	862.5	875.9	825.7	624.7
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		755.6					
FEB MINIMUM FLOW REQUIREMENT,CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	4/		18.1					
MIN JAN31 RESERVOIR CONTENT,KSFD	5/		0.0					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		1794.2					
JAN31 ECC,FT	7/		1794.2					
BASE ECC,FT		1856.5						
LOWER LIMIT, FT								
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.8	97.8				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		739.0	809.8				
MAR MINIMUM FLOW REQUIREMENT,CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW,KSFD	4/		15.3	15.3				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		0.0	0.0				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		1794.2	1794.2				
FEB28 ECC,FT.	7/		1794.2	1794.2				
BASE ECC,FT		1846.5						
LOWER LIMIT, FT								
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			95.3	95.3	97.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		720.1	789.1	840.1			
APR MINIMUM FLOW REQUIREMENT,CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW,KSFD	4/		12.2	12.2	12.2			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		0.0	0.0	0.0			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		1794.2	1794.2	1794.2			
MAR31 ECC,FT.	7/		1794.2	1794.2	1794.2			
BASE ECC,FT		1831.4						
LOWER LIMIT, FT								
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			89.2	89.2	91.1	93.5		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		674.0	738.6	785.7	819.0		
MAY MINIMUM FLOW REQUIREMENT,CFS	3/		100.0	100.0	100.0	100.0		
MIN MAY1-JUL31 OUTFLOW,KSFD	4/		9.2	9.2	9.2	9.2		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		41.0	0.0	0.0	0.0		
MIN APR30 RESERVOIR CONTENT,FEET	6/		1803.2	1794.2	1794.2	1794.2		
APR30 ECC,FT.	7/		1803.2	1794.2	1794.2	1794.2		
BASE ECC,FT		1831.5						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			67.6	67.6	69.1	70.9	75.8	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		510.8	559.8	596.0	621.0	625.9	
JUN MINIMUM FLOW REQUIREMENT,CFS	3/		100.0	100.0	100.0	100.0	100.0	
MIN JUN1-JUL31 OUTFLOW,KSFD	4/		6.1	6.1	6.1	6.1	6.1	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		201.1	152.1	115.9	90.9	86.0	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		1829.2	1821.9	1816.3	1812.1	1811.3	
MAY31 ECC,FT.	7/		1829.2	1821.9	1816.3	1812.1	1811.3	
BASE ECC,FT		1847.0						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			31.7	31.7	32.4	33.3	35.6	46.9
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		239.5	262.5	279.4	291.7	293.9	293.0
JUL MINIMUM FLOW REQUIREMENT,CFS	3/		100.0	100.0	100.0	100.0	100.0	100.0
MIN JUL1-JUL31 OUTFLOW,KSFD	4/		3.1	3.1	3.1	3.1	3.1	3.1
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		469.4	446.4	429.5	417.2	415.0	415.9
MIN JUN30 RESERVOIR CONTENT,FEET	6/		1864.4	1861.6	1859.5	1858.0	1857.7	1857.8
JUN30 ECC,FT.	7/		1864.4	1861.6	1859.5	1858.0	1857.7	1857.8
BASE ECC,FT		1871.4						
JUL 31 ECC, FT...................			1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (705.8 KSFD) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.

TABLE 5
1999 Variable Refill Curve
Libby Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW,KAF			7721.2	6941.1	7129.1	7000.2	6799.0	6657.0
PROBABLE DATE-31JULY INFLOW,KSFD			3892.7	3499.4	3594.2	3529.2	3427.8	3356.2
95% FORECAST ERROR FOR DATE, KSFD			886.8	606.4	552.5	533.4	474.5	367.5
OBSERVED JAN1-DATE INFLOW, IN KSFD			0.0	126.5	231.4	363.0	644.3	1386.5
95% CONF.DATE-31JULY INFLOW,KSFD	1/		3005.9	2766.5	2810.3	2632.8	2309.0	1602.3
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			97.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		2914.5					
FEB MINIMUM FLOW REQUIREMENT,CFS	3/		5000.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	4/		1515.0					
MIN JAN31 RESERVOIR CONTENT,KSFD	5/		1111.0					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		2387.2					
JAN31 ECC,FT.	7/		2387.2					
BASE ECC, FT		2416.6						
LOWER LIMIT,FT		2291.3						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			94.2	97.1				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		2830.9	2687.3				
MAR MINIMUM FLOW REQUIREMENT,CFS	3/		5000.0	5000.0				
MIN MAR1-JUL31 OUTFLOW,KSFD	4/		1375.0	1375.0				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		1054.5	1198.2				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		2383.3	2392.9				
FEB28 ECC,FT.	7/		2383.3	2392.9				
BASE ECC,FT		2413.8						
LOWER LIMIT,FT		2287.0						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			90.8	93.7	96.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		2729.7	2591.1	2709.7			
APR MINIMUM FLOW REQUIREMENT,CFS	3/		5000.0	5000.0	5000.0			
MIN APR1-JUL31 OUTFLOW,KSFD	4/		1220.0	1220.0	1220.0			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		1000.8	1139.4	1020.8			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		2379.6	2389.1	2381.0			
MAR31 ECC,FT.	7/		2379.6	2389.1	2381.0			
BASE ECC,FT		2411.0						
LOWER LIMIT,FT		2287.0						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			82.7	85.3	87.8	91.1		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		2485.9	2359.5	2467.4	2397.7		
MAY MINIMUM FLOW REQUIREMENT,CFS	3/		5000.0	5000.0	5000.0	5000.0		
MIN MAY1-JUL31 OUTFLOW,KSFD	4/		1070.0	1070.0	1070.0	1070.0		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		1094.6	1221.0	1113.1	1182.8		
MIN APR30 RESERVOIR CONTENT,FEET	6/		2386.0	2394.4	2387.3	2391.9		
APR30 ECC,FT.	7/		2386.0	2394.4	2387.3	2391.9		
BASE ECC,FT		2410.1						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			55.3	57.0	58.7	60.9	66.9	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		1661.7	1577.4	1649.6	1602.8	1543.6	
JUN MINIMUM FLOW REQUIREMENT,CFS	3/		15000.0	15000.0	15000.0	15000.0	5000.0	
MIN JUN1-JUL31 OUTFLOW,KSFD	4/		915.0	915.0	915.0	915.0	915.0	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		1763.8	1848.1	1775.9	1822.7	1881.9	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		2424.6	2428.8	2425.2	2427.5	2430.5	
MAY31 ECC,FT.	7/		2424.6	2428.8	2425.2	2427.5	2430.3	
BASE ECC,FT		2430.3						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			19.6	20.2	20.8	21.6	23.7	35.5
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		589.2	559.4	584.8	568.1	547.2	568.0
JUL MINIMUM FLOW REQUIREMENT,CFS	3/		15000.0	15000.0	15000.0	15000.0	5000.0	15000.0
MIN JUL1-JUL31 OUTFLOW,KSFD	4/		465.0	465.0	465.0	465.0	465.0	465.0
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		2386.3	2416.1	2390.7	2407.3	2428.3	2407.5
MIN JUN30 RESERVOIR CONTENT,FEET	6/		2453.6	2454.9	2453.8	2454.5	2455.4	2454.5
JUN30 ECC,FT.	7/		2453.6	2454.9	2453.8	2454.5	2455.4	2454.5
BASE ECC,FT		2459.0						
JUL 31 ECC, FT			2459.0	2459.0	2459.0	2459.0	2459.0	2459.0
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF	8/		117.0	120.0	125.0	128.0	124.0	124.0

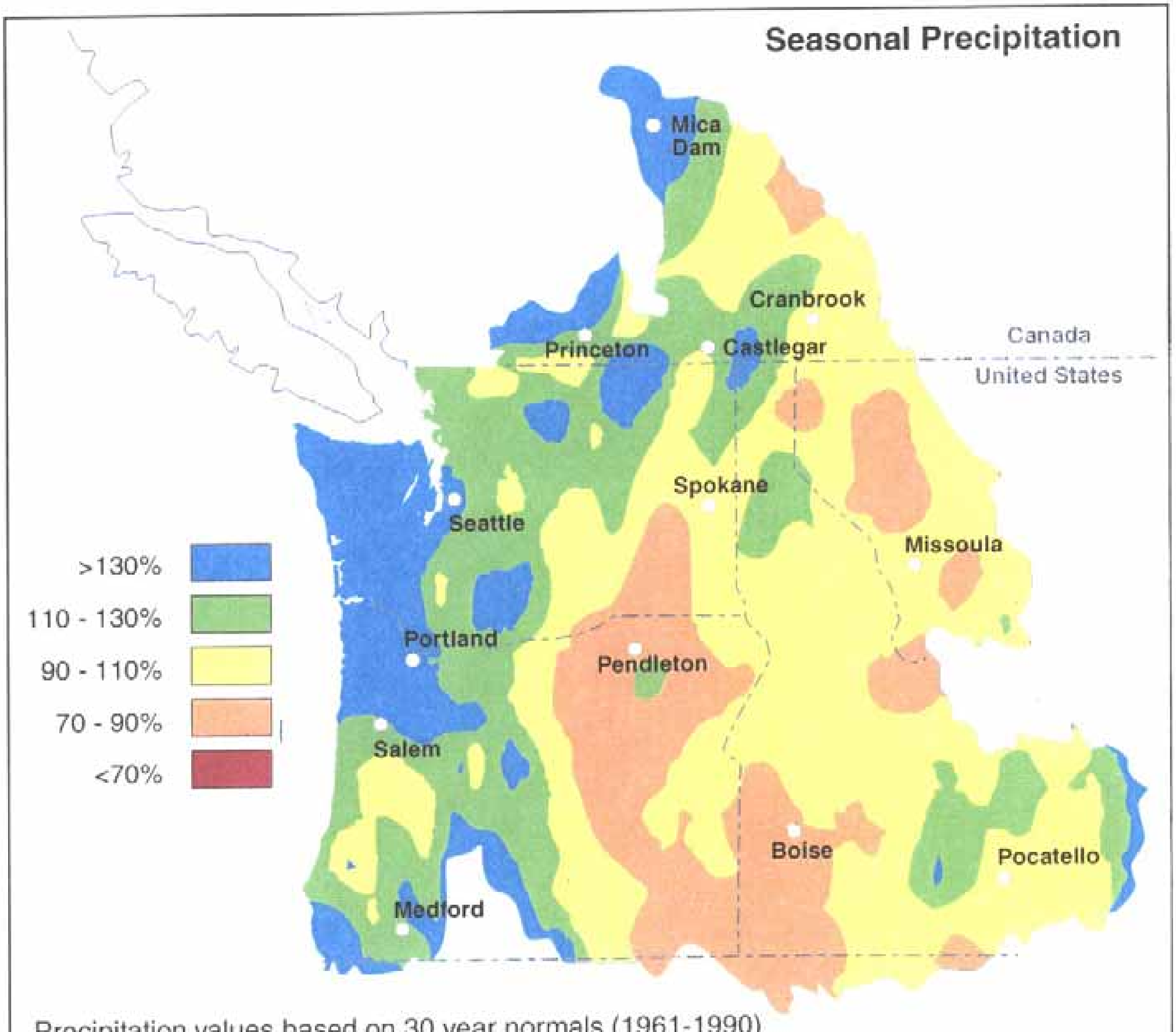
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW) MINUS OBSERVED INFLOW. 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (2510.5 KSFD) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.A143
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.
8/ USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR 3/.

Table 6

Computation of Initial Controlled Flow
Columbia River at The Dalles
1 May 1999

1 May Forecast of May-August Unregulated Runoff Volume, Maf		93.2
Less Estimated Depletions, Maf		1.5
Less Upstream Storage Corrections, Maf		29.020
MICA	7.275	
ARROW	5.000	
DUNCAN	1.382	
LIBBY	4.021	
LIBBY + DUNCAN UNDER DRAFT	0.000	
HUNGRY HORSE	1.421	
FLATHEAD LAKE	0.500	
NOXON RAPIDS	0.000	
PEND OREILLE LAKE	0.500	
GRAND COULEE	4.602	
BROWNLEE	0.7	
DWORSHAK	1.939	
JOHN DAY	0.180	
TOTAL	29.020	29.020
Forecast of Adjusted Residual Runoff Volume, Maf		64.180
Computed Initial Controlled Flow from Chart 1 of Flood Control Operating Plan, 1,000 cfs		416

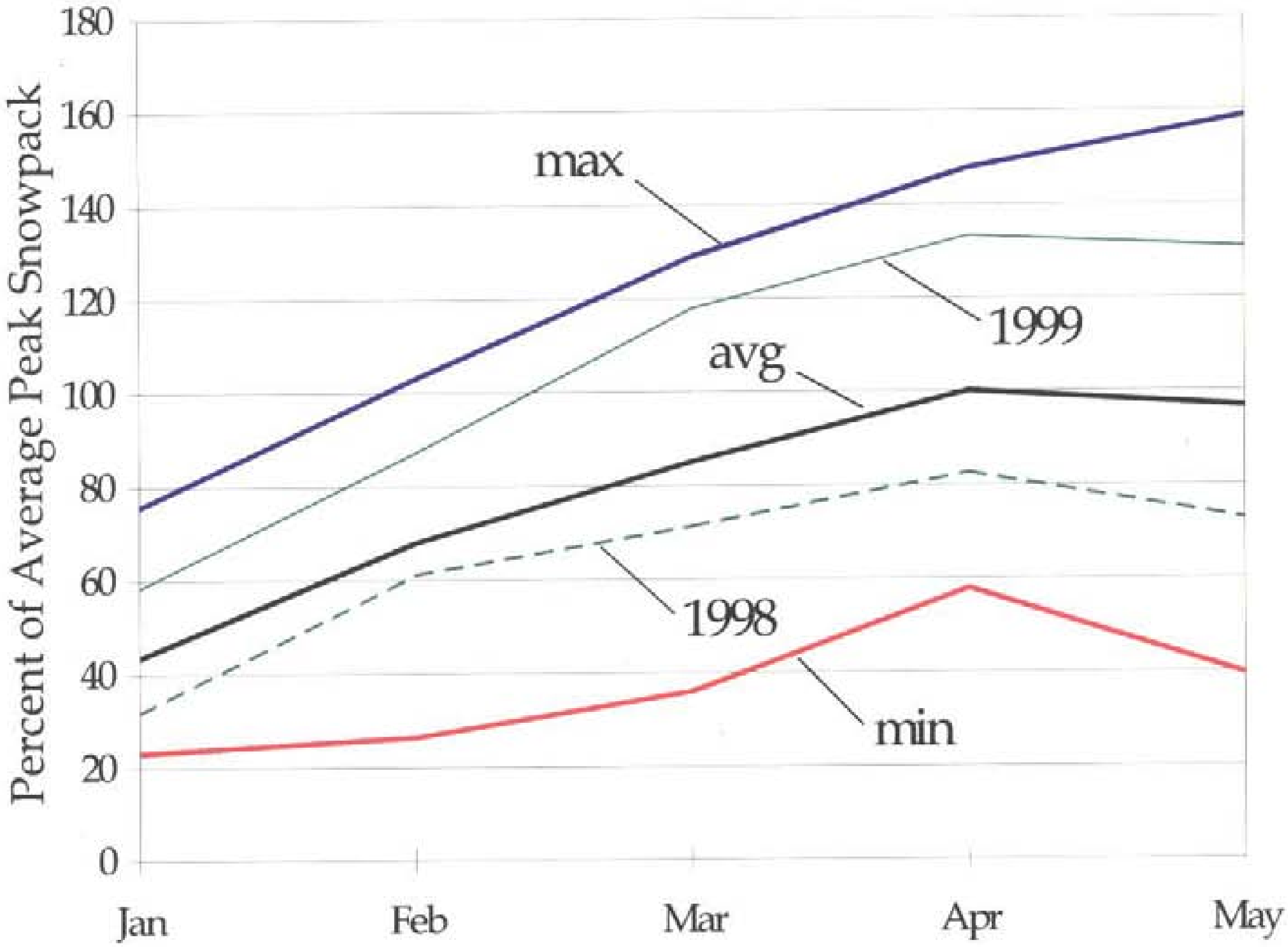
Chart 1
Seasonal Precipitation
Columbia River Basin
October 1998 - September 1999
Percent of 1961 - 1985 Average

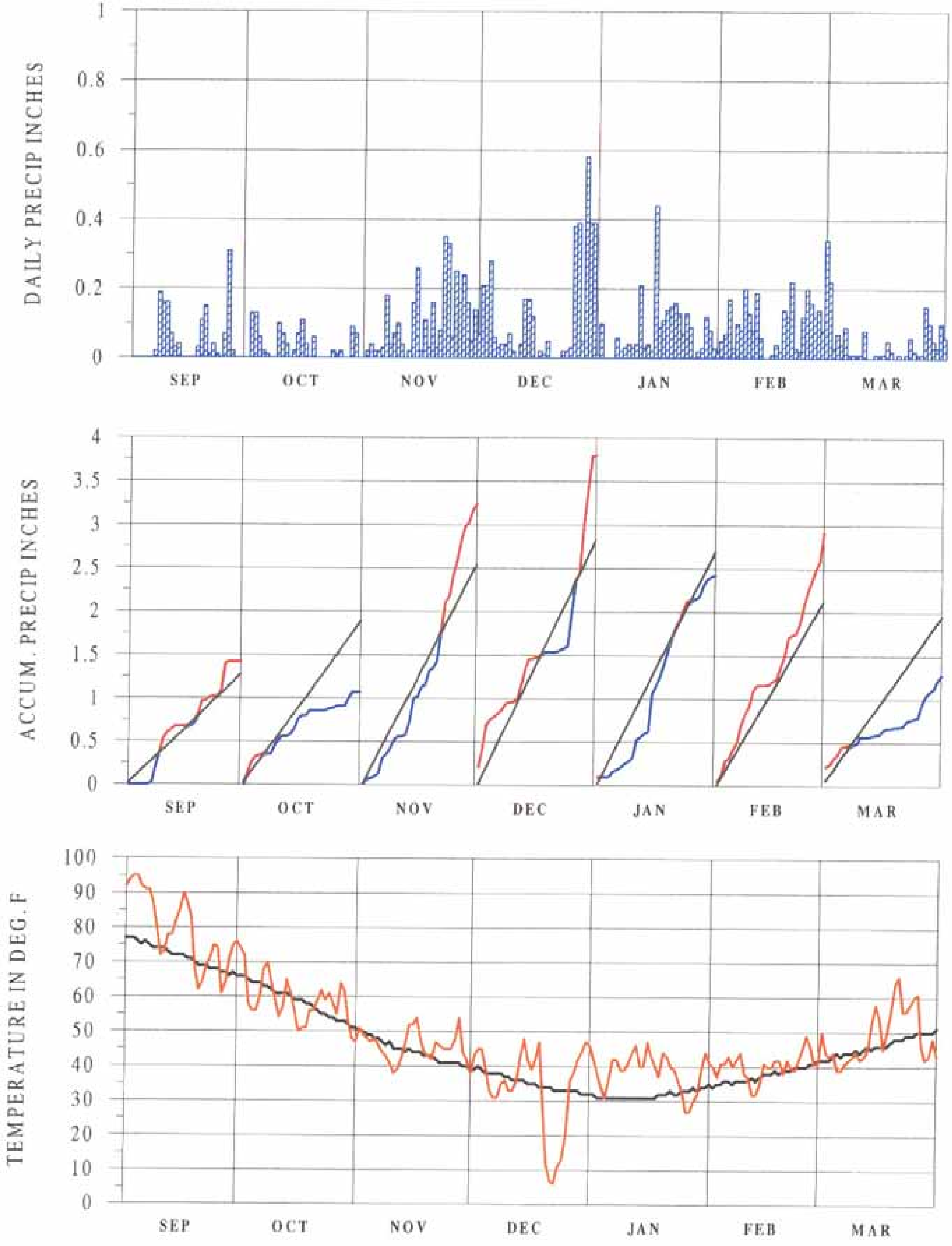


Precipitation values based on 30 year normals (1961-1990)

Information prepared by
NATIONAL WEATHER SERVICE
Northwest River Forecast Center
Portland, Oregon

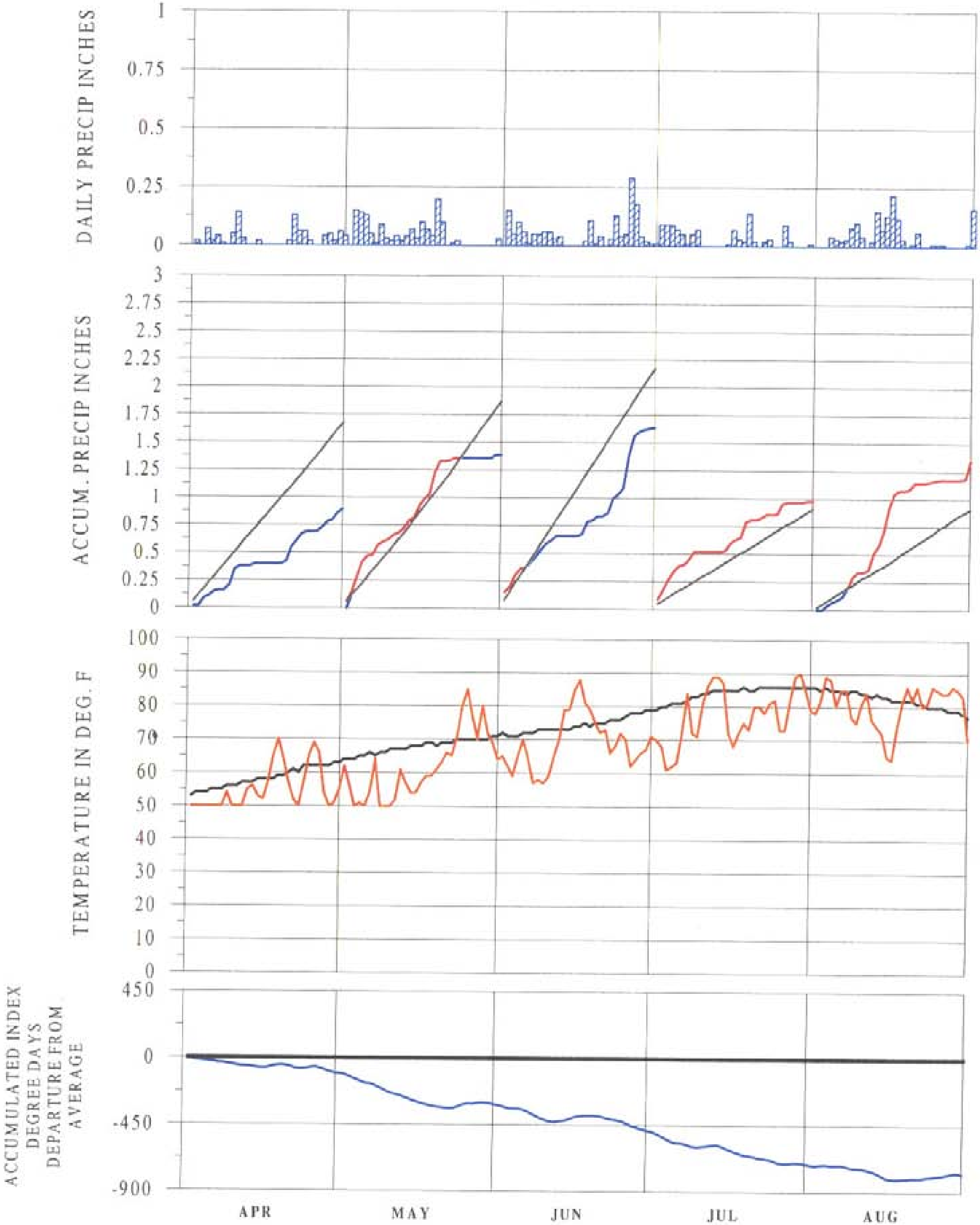
Chart 2
Columbia Basin Snowpack





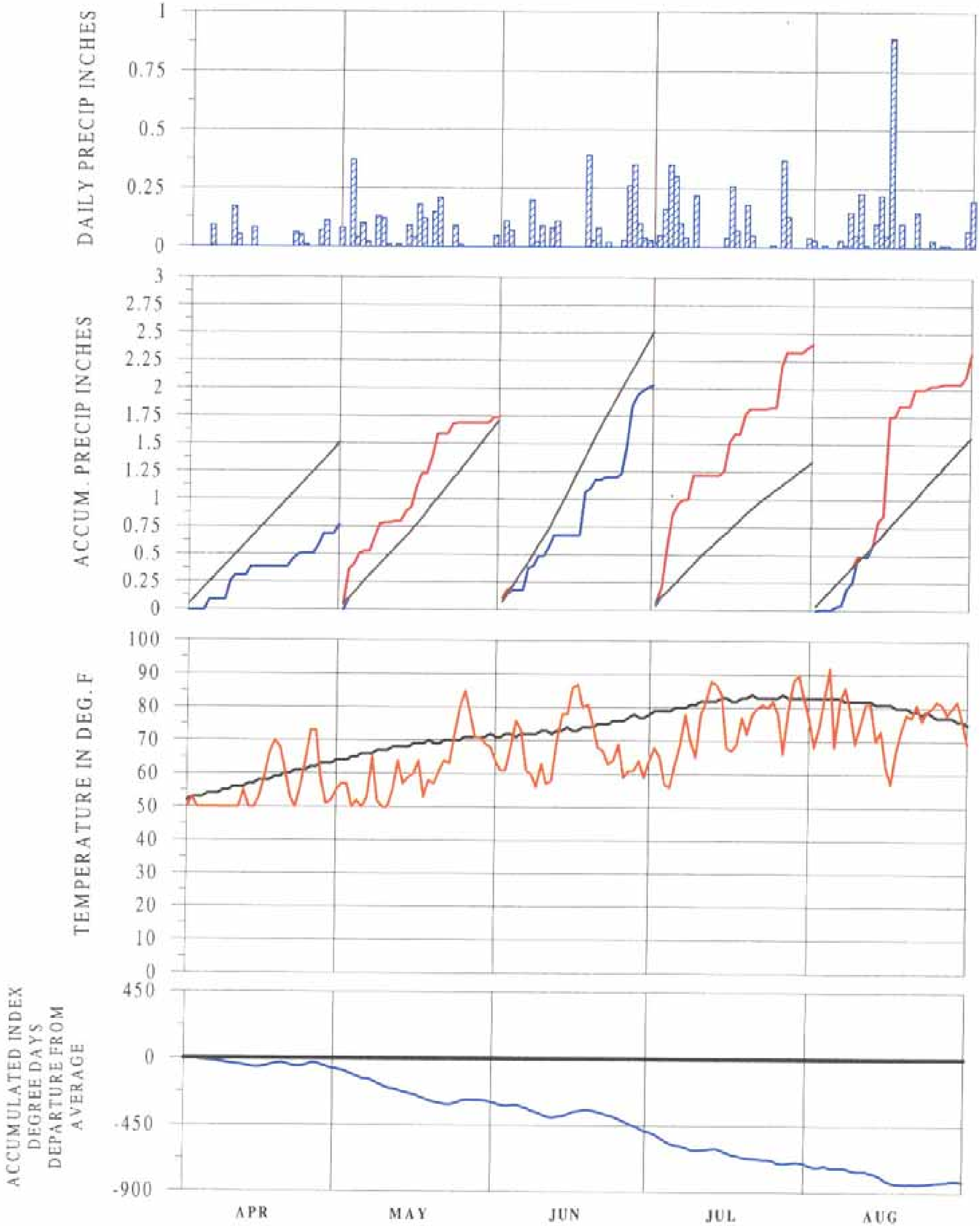
WINTER SEASON
TEMPERATURE AND PRECIPITATION INDEX 1998-1999
COLUMBIA RIVER BASIN ABOVE THE DALLES, OREGON

CHART 3



SNOWMELT SEASON
TEMPERATURE AND PRECIPITATION INDEX 1999
COLUMBIA RIVER ABOVE THE DALLES, OR

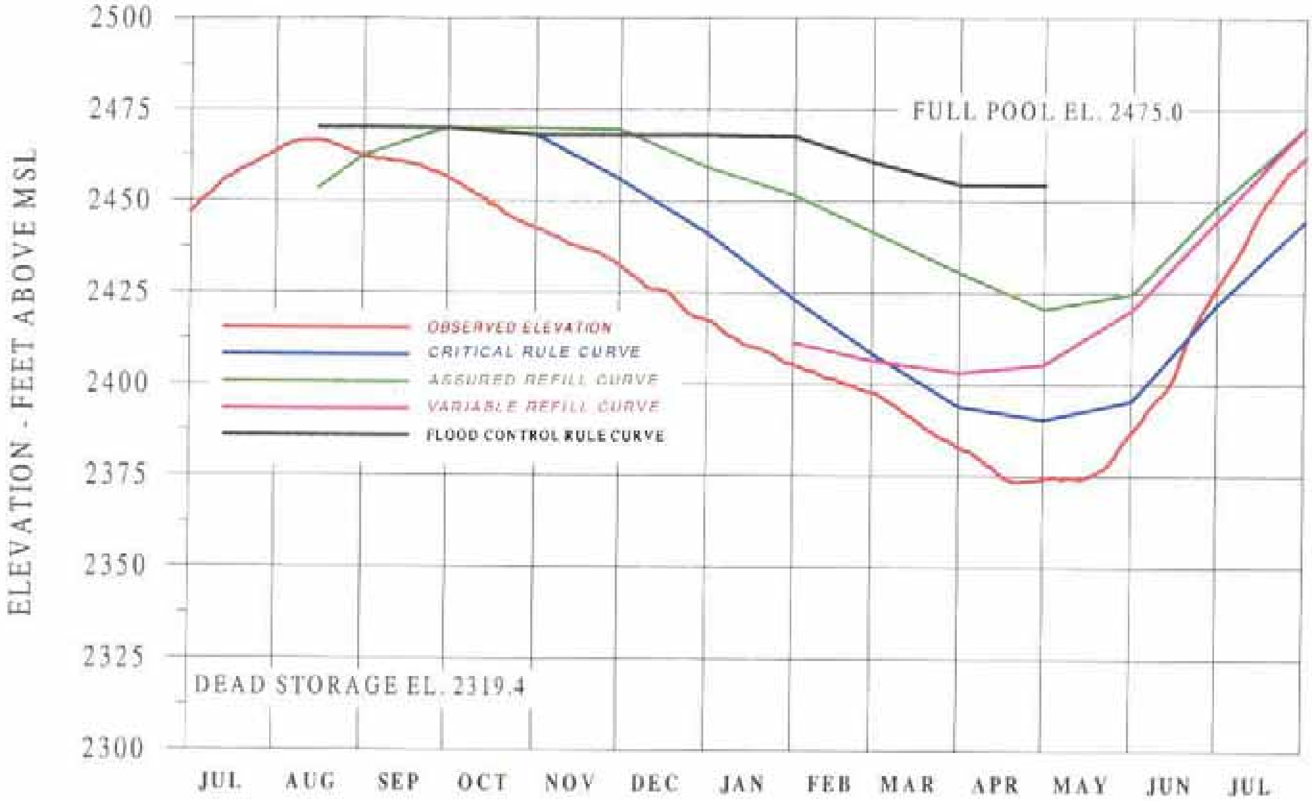
CHART 4



SNOWMELT SEASON
TEMPERATURE AND PRECIPITATION INDEX 1999
COLUMBIA RIVER BASIN IN CANADA

CHART 5

CHART 6
REGULATION OF MICA
1 JULY 1998 - 31 JULY 1999



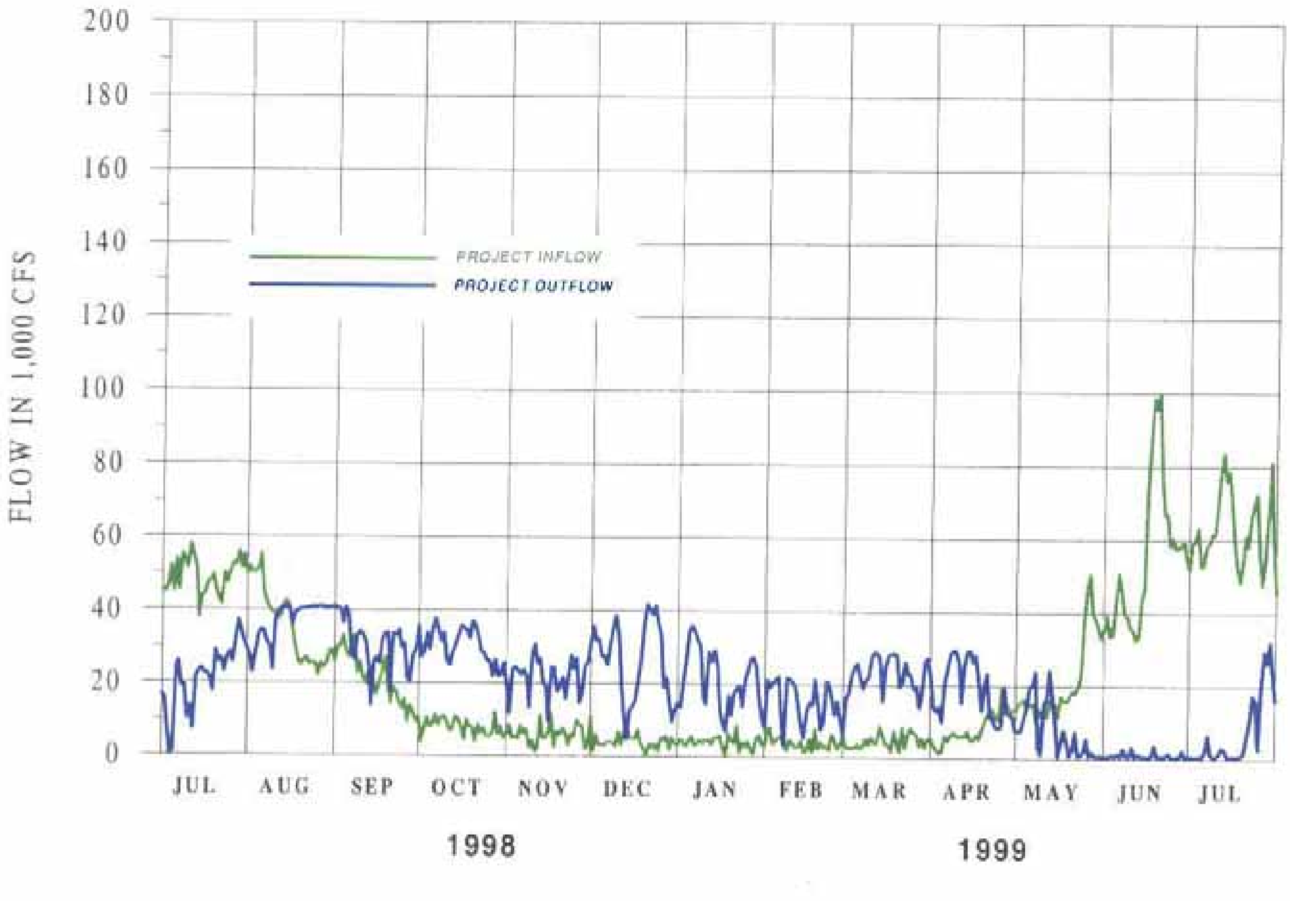
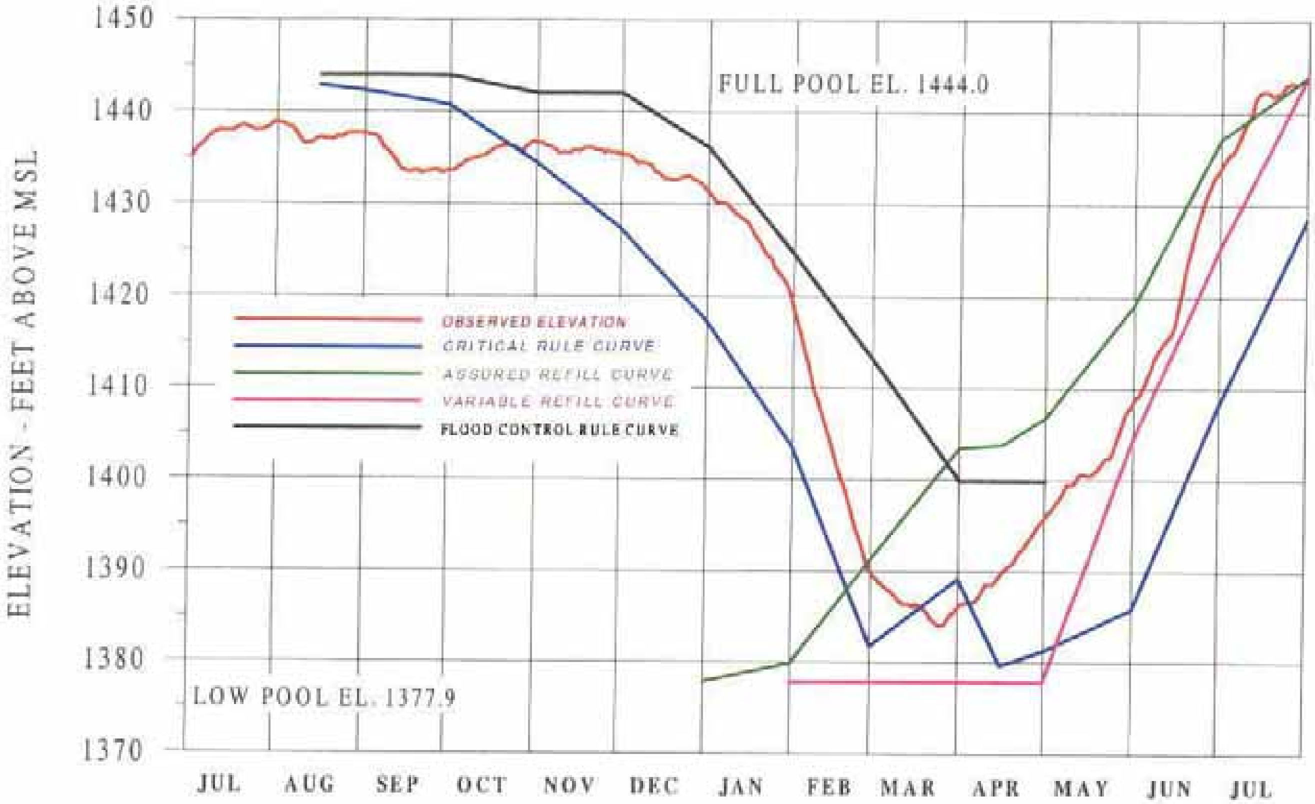


CHART 7
REGULATION OF ARROW
1 JULY 1998 - 31 JULY 1999



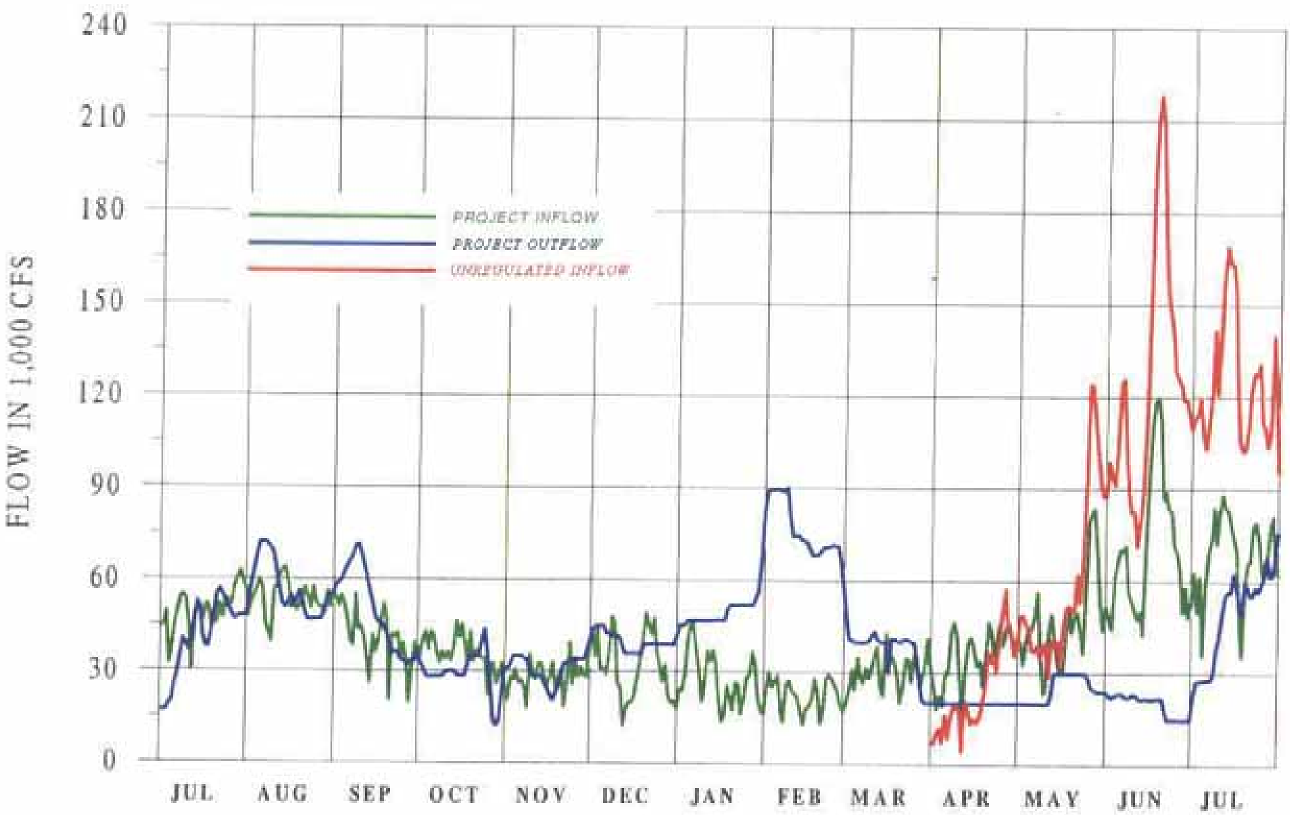
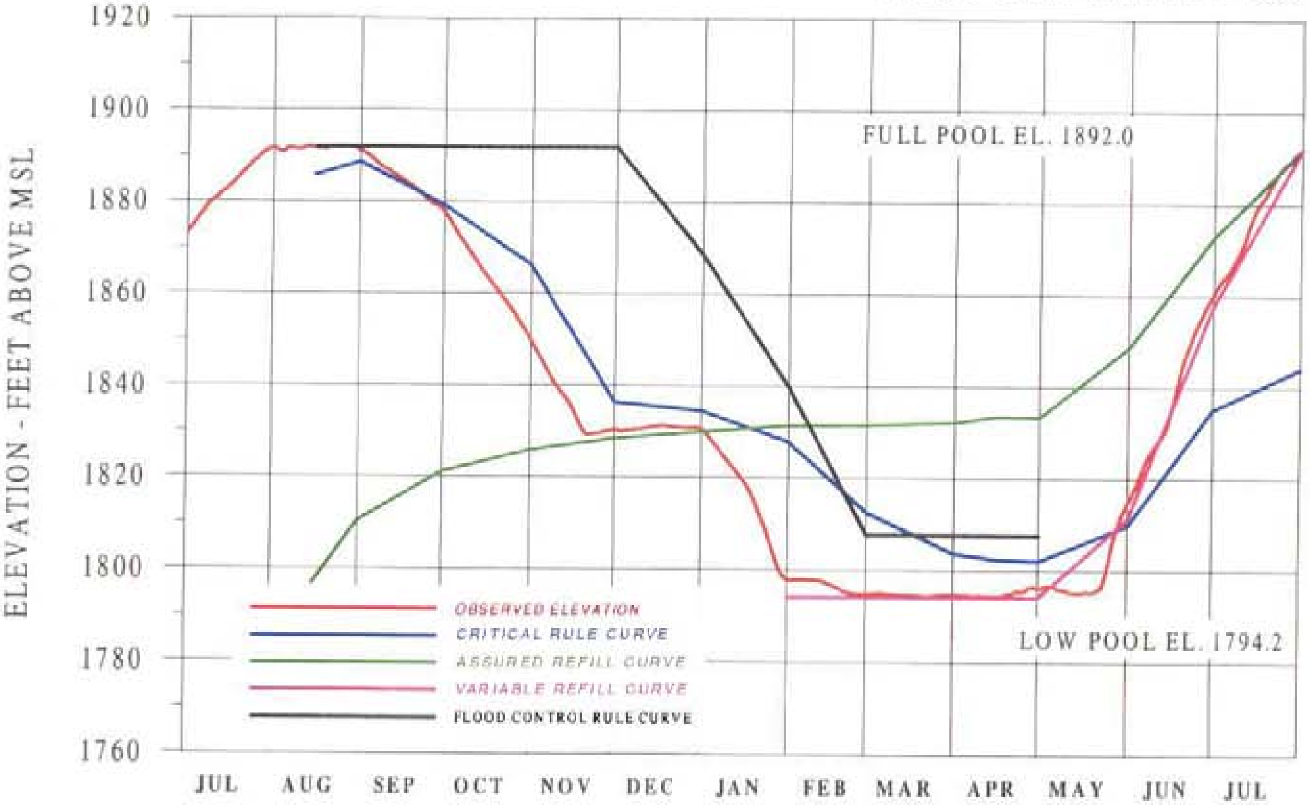


CHART 8
REGULATION OF DUNCAN
1 JULY 1998 - 31 JULY 1999



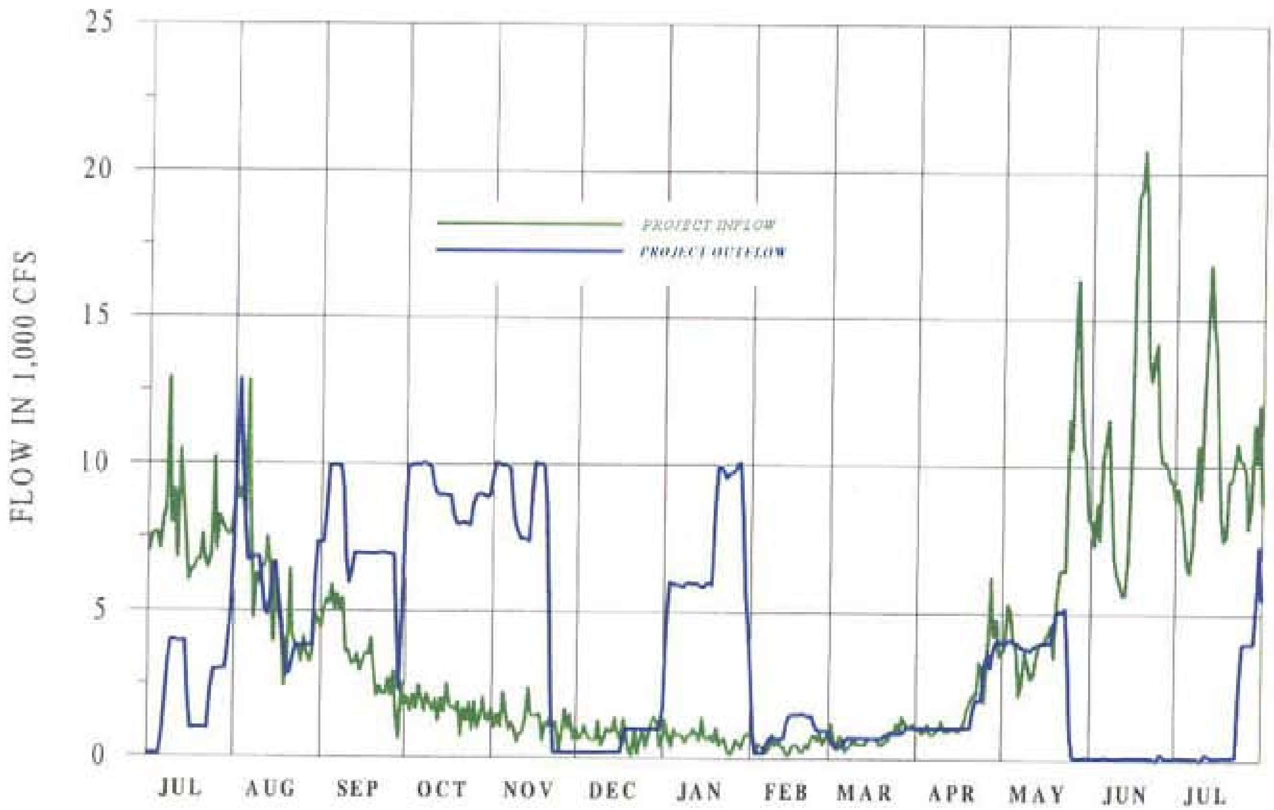
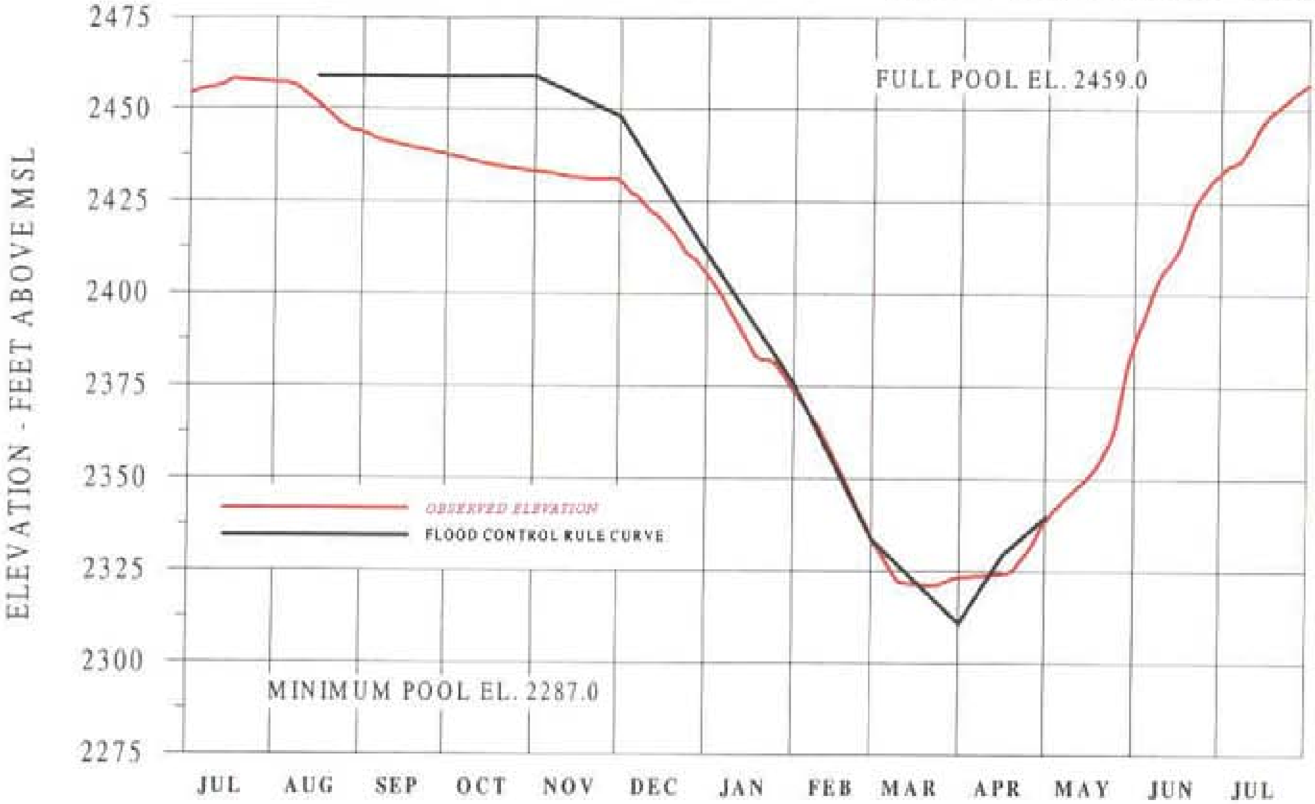


CHART 9
REGULATION OF LIBBY
1 JULY 1998 - 31 JULY 1999



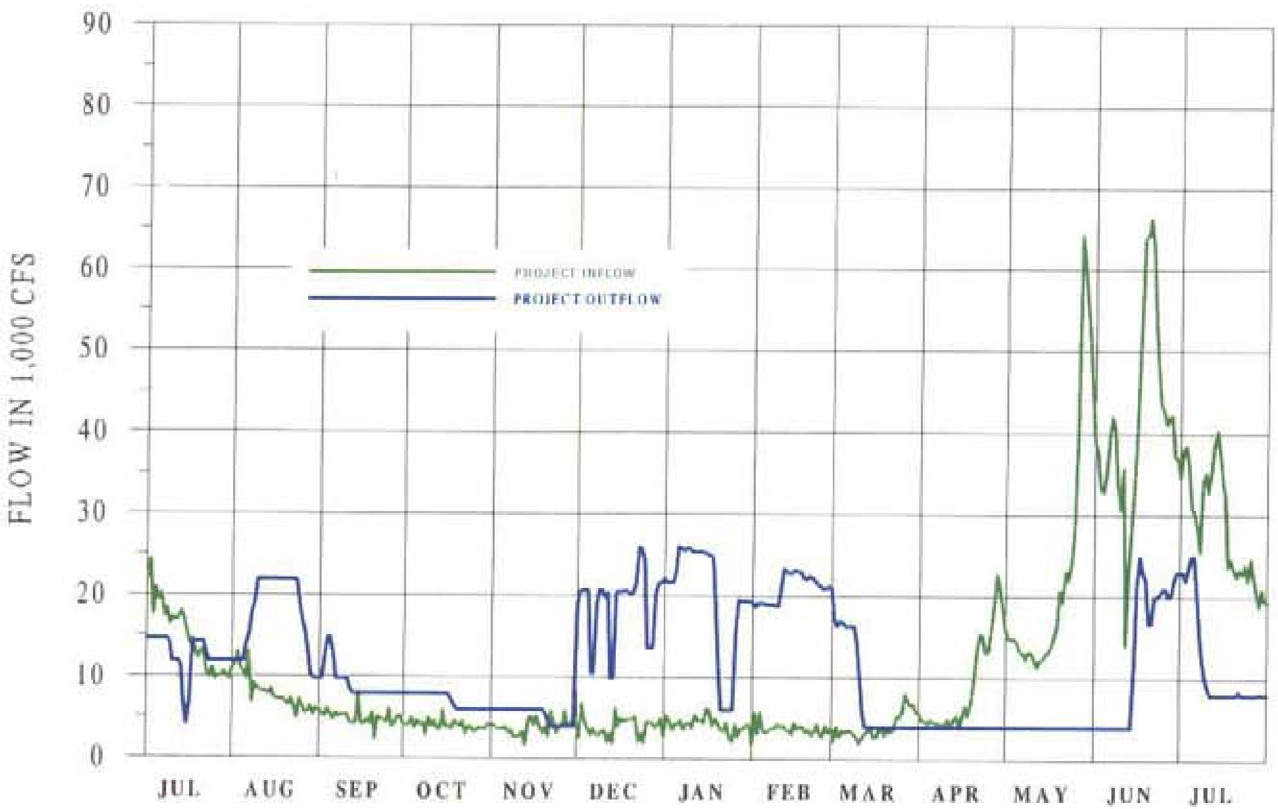
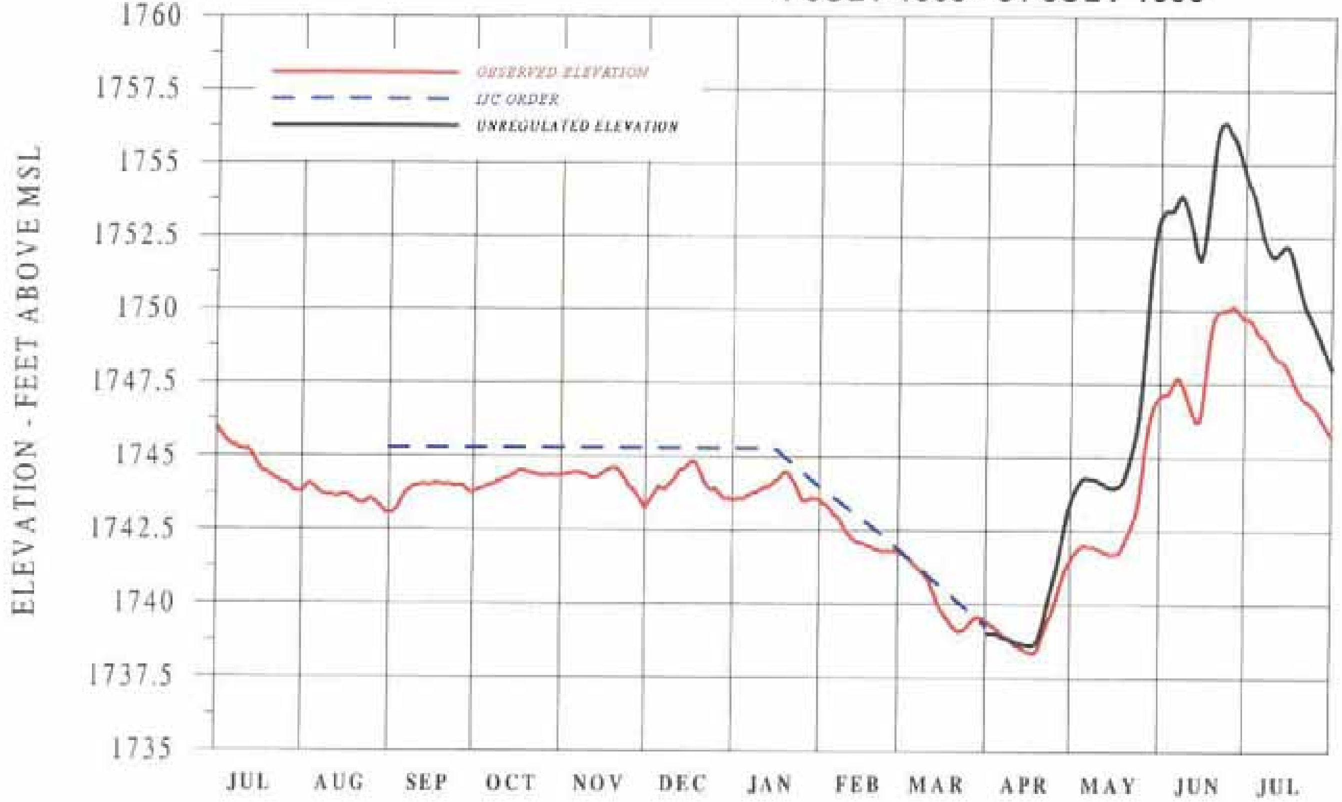


CHART 10
REGULATION OF KOOTENAY LAKE
1 JULY 1998 - 31 JULY 1999



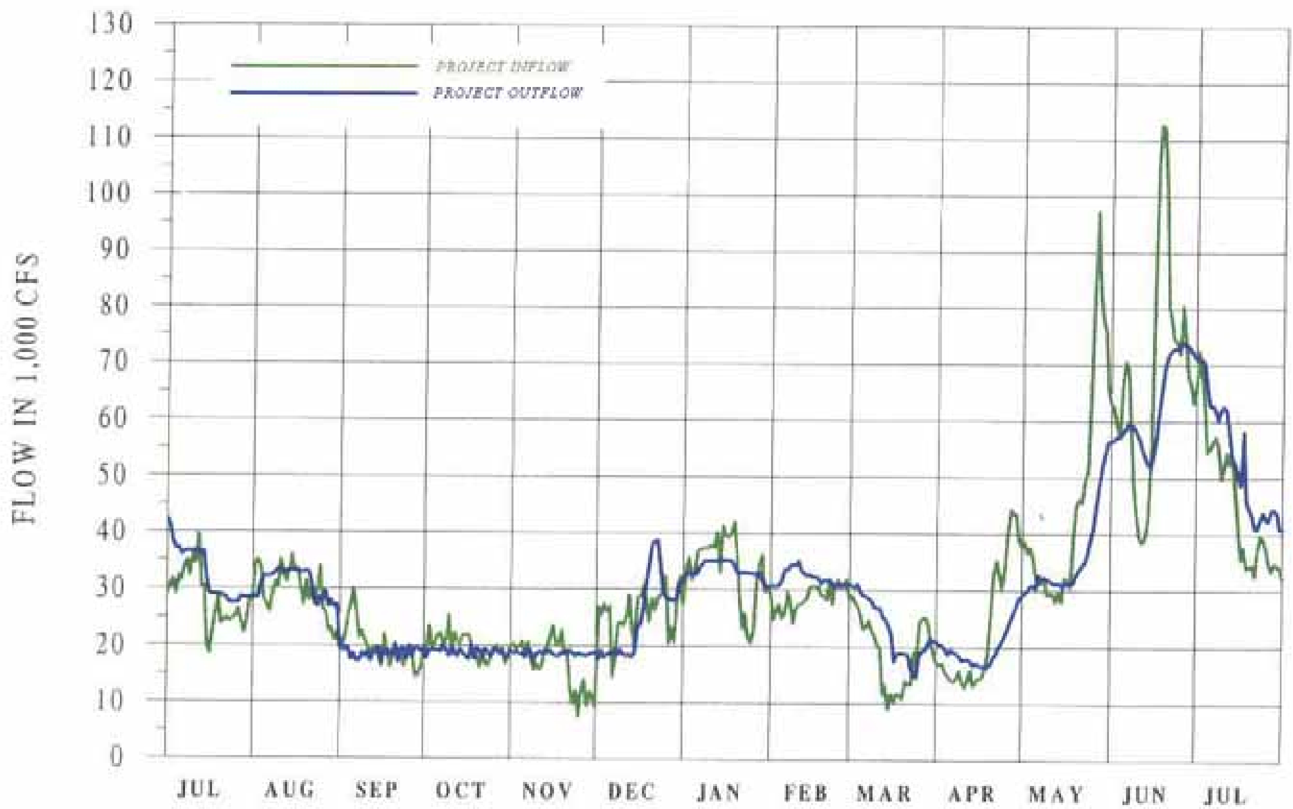
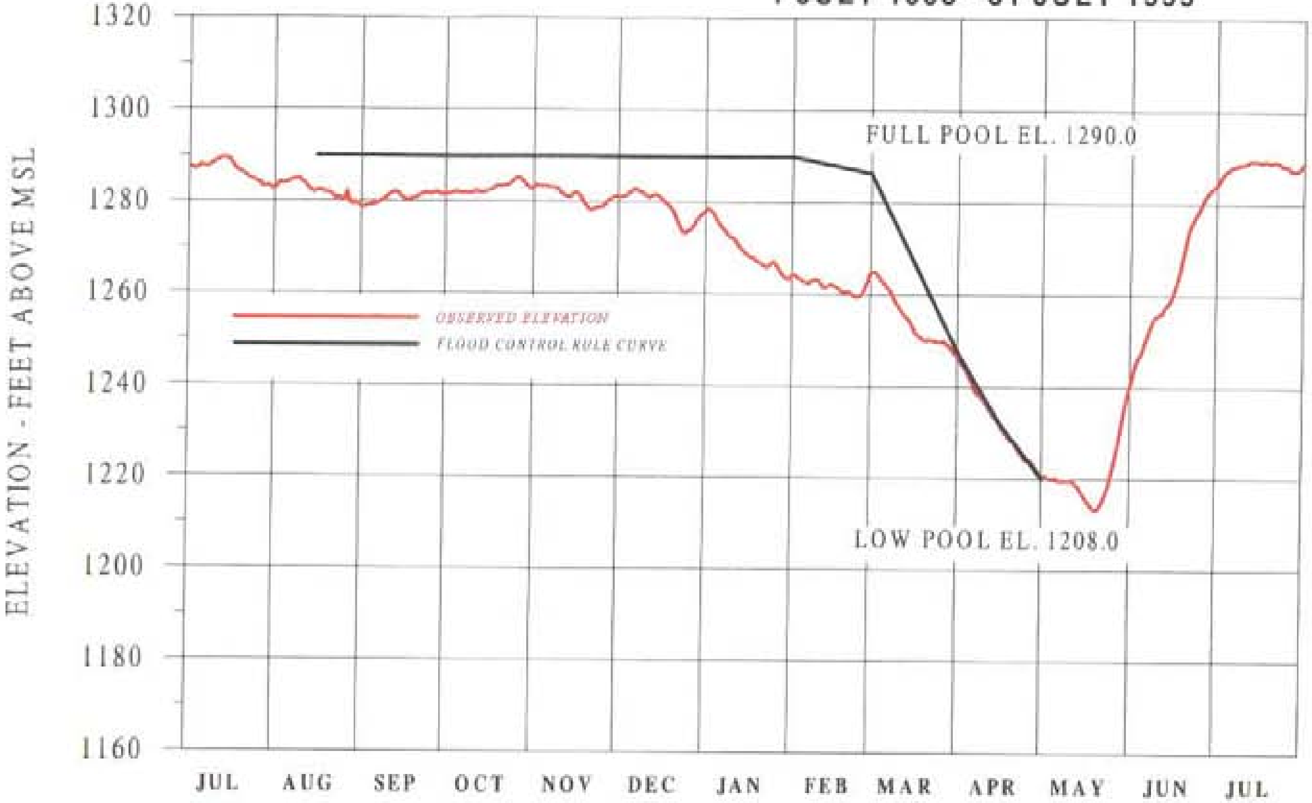



CHART 11
COLUMBIA RIVER AT BIRCHBANK
1 JULY 1998 - 31 JULY 1999
OBSERVED FLOW
UNREGULATED FLOW
BANKFULL AT TRAIL, B.C. 225 KCFS
FLOW IN 1,000 CFS
0
20
40
60
80
100
120
140
160
180
200
220
240
260
280
300
320
JUL
AUG
SEP
OCT
NOV
DEC
JAN
FEB
MAR
APR
MAY
JUN
JUL

CHART 12
REGULATION OF GRAND COULEE
1 JULY 1998 - 31 JULY 1999



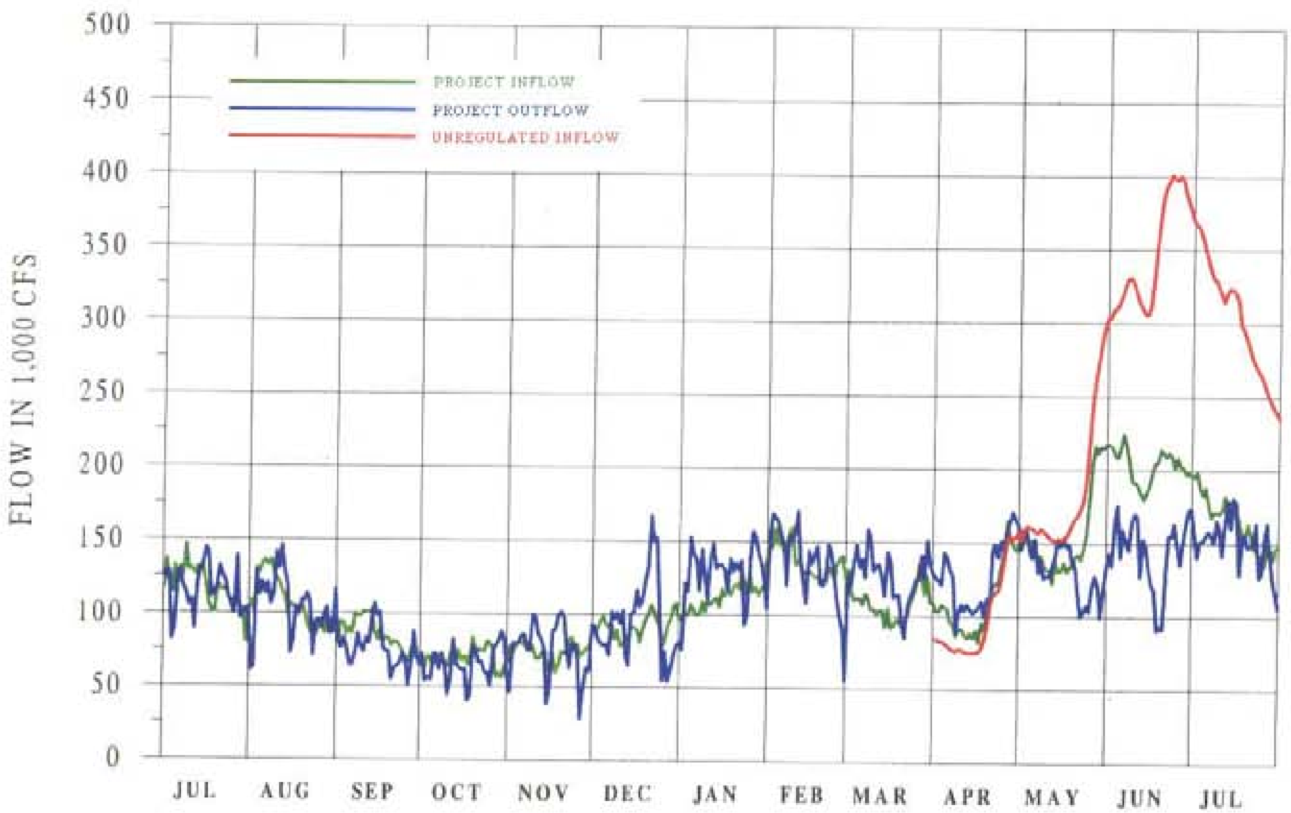


CHART13
COLUMBIA RIVER AT THE DALLES
1 JULY 1998 - 31 JULY 1999

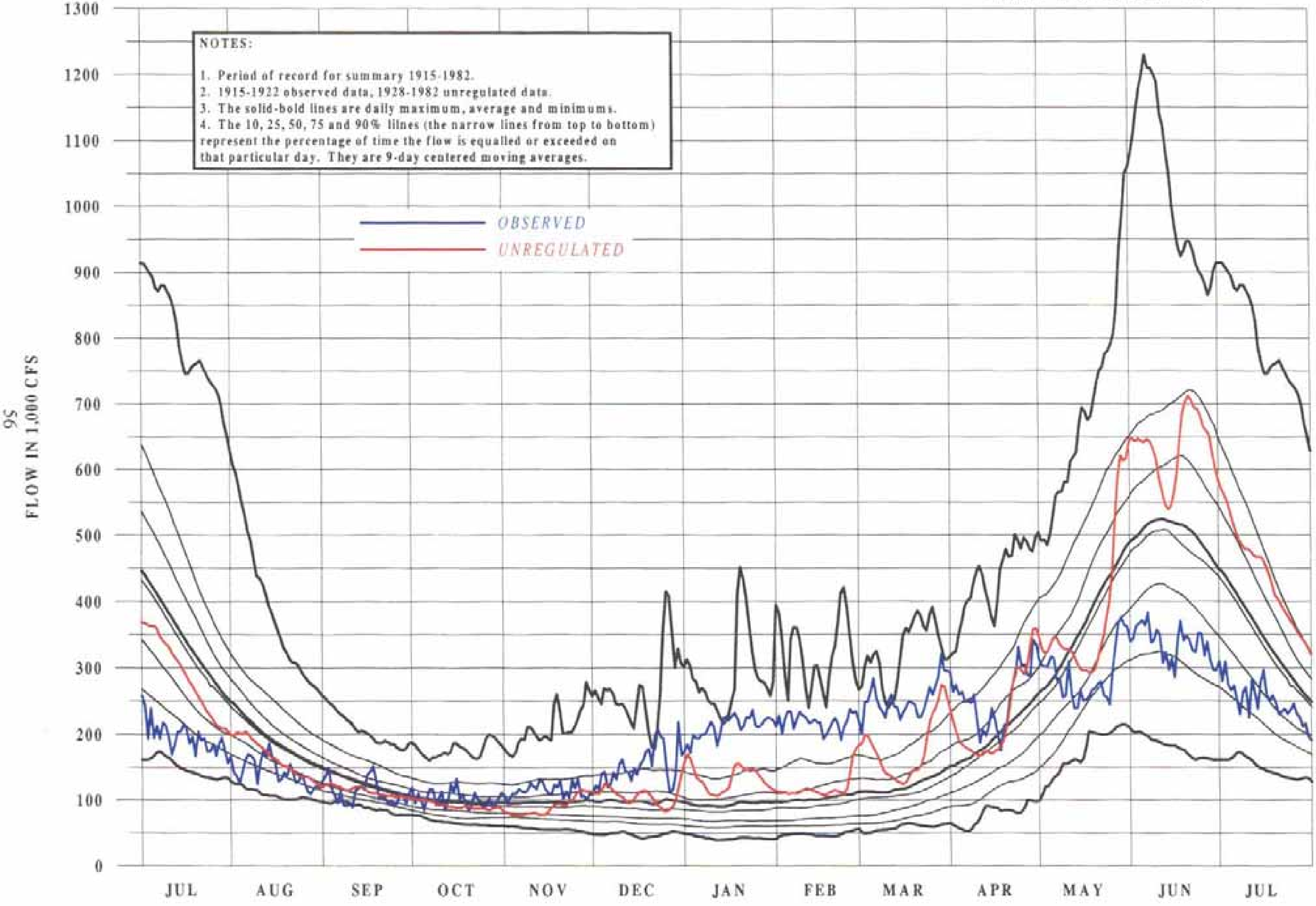
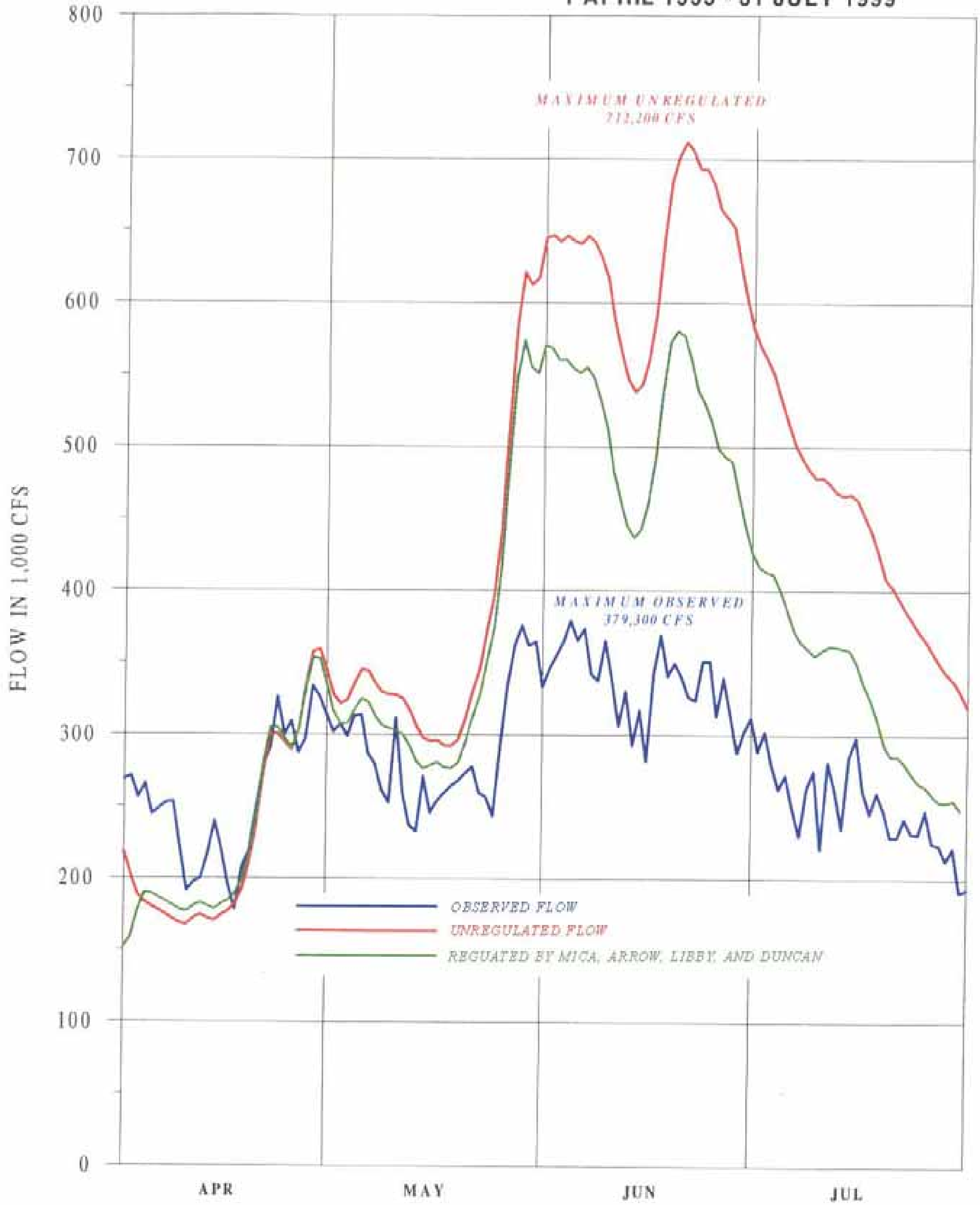


CHART 14
COLUMBIA RIVER AT THE DALLES
1 APRIL 1999 - 31 JULY 1999



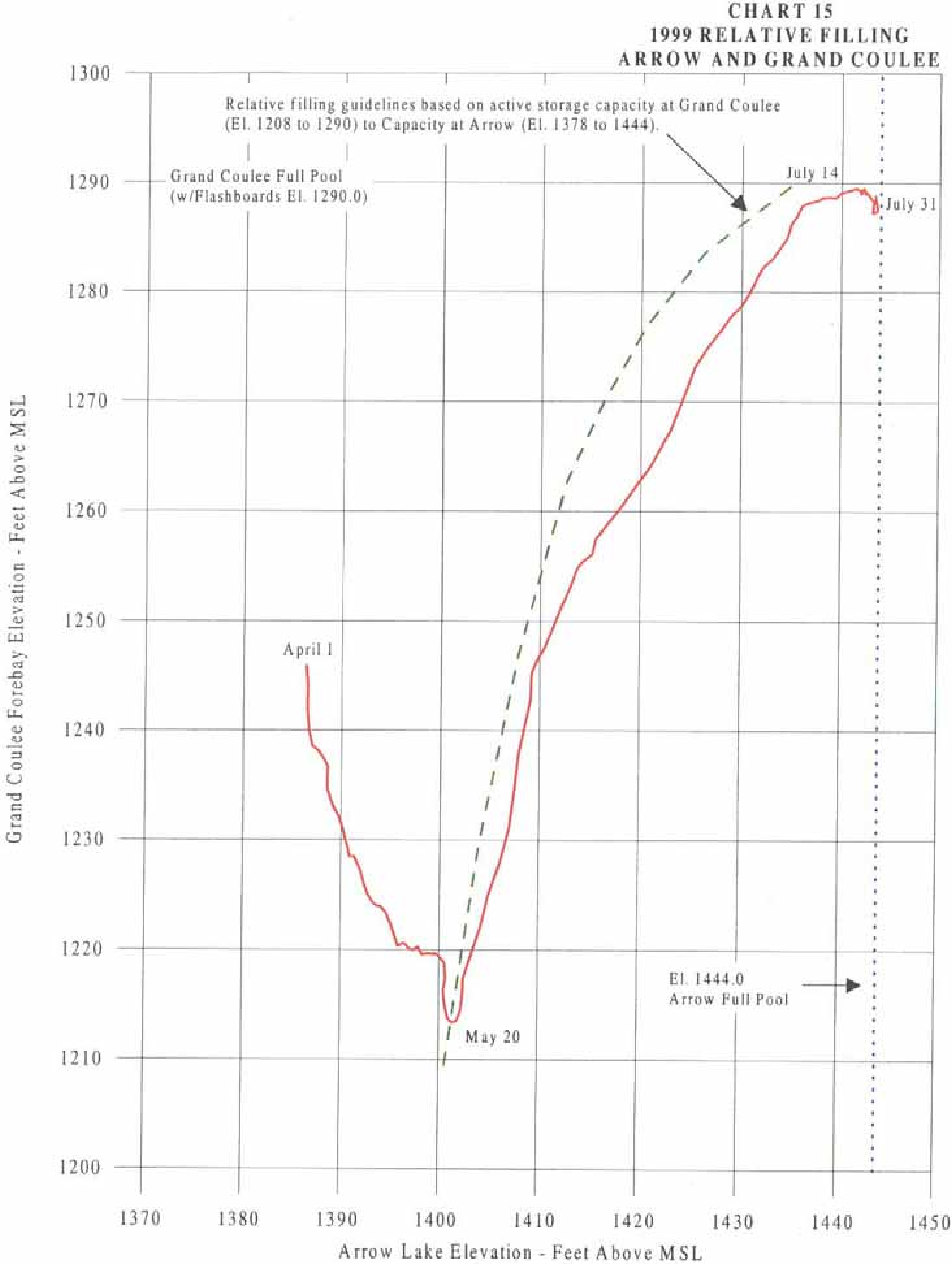


CHART 15
1999 RELATIVE FILLING
ARROW AND GRAND COULEE
Relative filling guidelines based on active storage capacity at Grand Coulee (El. 1208 to 1290) to Capacity at Arrow (El. 1378 to 1444).
Grand Coulee Full Pool (w/Flashboards El. 1290.0)
July 14
July 31
April 1
May 20
El. 1444.0 Arrow Full Pool
Grand Coulee Forebay Elevation - Feet Above MSL
Arrow Lake Elevation - Feet Above MSL
1300
1290
1280
1270
1260
1250
1240
1230
1220
1210
1200
1370
1380
1390
1400
1410
1420
1430
1440
1450